

**BEFORE THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION
DOCKET NO. 2020-229-E**

In the Matter of:)
Dominion Energy South Carolina,)
Incorporated's Establishment of a)
Solar Choice Metering Tariff Pursuant)
to S.C. Code Ann. Section 58-40-20)

**REDACTED
DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION AND
SOLAR ENERGY INDUSTRIES ASSOCIATION**

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the Solar Energy Industries Association (“SEIA”) and the North Carolina Sustainable Energy Association (“NCSEA”).

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION (“COMMISSION”)?

A. Yes. I submitted testimony on behalf of The Alliance for Solar Choice in Commission Docket No. 2014-246-E addressing the implementation of 2014 Public Act 236, and in Docket Nos. 2015-53-E, 2015-54-E, and 2015-55-E addressing the applications of the state’s three investor-owned utilities (“IOUs”) to establish distributed energy resource (“DER”) programs pursuant to the South Carolina Distributed Energy Resource Act (“Act 236”) (enacted by the General Assembly in S.1189 (2014)). I also submitted testimony on behalf of Vote Solar in Docket Nos. 2018-318-E and 2018-319-E, which addressed the Duke Energy affiliates’ most recent South Carolina rate case applications. Most recently I submitted testimony on behalf of SEIA and NCSEA in Docket No. 2019-182-E related to the Commission’s generic evaluation of the costs and benefits of net

metering (“the Generic Docket”) pursuant to the South Carolina Energy Freedom Act (“Act 62”) (enacted by the General Assembly in H.3659 (2019)).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years as a Policy Analyst and Senior Policy Analyst.¹ During that time I worked on the *Database of State Incentives for Renewables and Efficiency* (“DSIRE”) project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst and became the Director of Research in 2015. In my current position, I coordinate and contribute to EQ Research’s various research projects for clients, assist in the oversight of EQ Research’s electric industry regulatory and general rate case tracking services, and perform customized research and analyses to fulfill client requests.

Q. PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE AS IT RELATES TO THIS PROCEEDING.

A. My professional career has been spent researching and analyzing numerous aspects of federal and state energy policy, spanning more than a decade. Throughout that time, I have reviewed and evaluated trends in regulatory policy, including trends in DG policy, rate design and cost of service. For example, I

¹ The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

1 have closely followed the progression of regulators' interest and investigations of
2 DG costs and benefits and cost of service and resulting determinations for the
3 better part of the last decade.

4 Outside of South Carolina I have submitted testimony before utility
5 regulatory commissions in Colorado, Georgia, Hawaii, Kentucky, New
6 Hampshire, New Jersey, New York, North Carolina, Oklahoma, Texas, Utah, and
7 Virginia, as well as to the City Council of New Orleans, on various issues related
8 to distributed generation ("DG") policy, net metering, rate design, and cost of
9 service.² These individual regulatory proceedings have involved a mix of general
10 rate cases and other types of contested cases. My *curriculum vitae* is attached as
11 Exhibit JRB-1. It contains summaries of the subject matter I have addressed in
12 each of these proceedings.

13 **Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY AND HOW**
14 **IT IS ORGANIZED.**

15 A. The purpose of my testimony is to provide an analysis of the Solar Choice tariffs
16 proposed by Dominion Energy South Carolina ("Dominion" or "the Company");
17 describe the deficiencies in the Company's proposal with respect to the
18 requirements of Act 62; delineate best practices in net energy metering ("NEM")
19 successor design and other design considerations; and propose an alternative Solar
20 Choice tariff design for Commission consideration. My testimony is organized as
21 follows:

² The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state utility regulatory commissions.

- 1 • Section II contains a discussion of high-level considerations reflecting the
- 2 whole of the Company's proposal broken into subsections covering NEM
- 3 successor best practices and solar customer cost of service.
- 4 • Section III contains subsections addressing each element of the
- 5 Company's Solar Choice tariff proposal and my recommendations to the
- 6 Commission on each. My recommendations collectively comprise my
- 7 alternative Solar Choice tariff proposal.
- 8 • Section IV provides an analysis of how the Company's proposed Solar
- 9 Choice tariff would affect the customer economics of customer-sited solar,
- 10 including the deficiencies I have identified in the Company's
- 11 representations of those impacts.
- 12 • Section V contains my concluding remarks.

13 **Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION**

14 **FOR THE DESIGN OF A SOLAR CHOICE TARIFF?**

15 A. I recommend that the Commission reject the Company's proposed Solar Choice

16 tariff and instead adopt a Solar Choice tariff with the following elements:

- 17 1. BFC and Minimum Bill: Solar Choice basic facilities charges ("BFCs")
- 18 are set at the amount for the otherwise applicable rate schedule and a
- 19 minimum bill is set at the amount established for the otherwise applicable
- 20 time-of-use ("TOU") rate option.
- 21 2. Mandatory TOU Rate: Solar Choice customers take TOU service and may
- 22 do so under any TOU rate that would be available to them if they were not
- 23 Solar Choice customers. However, I suggest that the Commission delay

1 implementation of mandatory TOU under Solar Choice until it is confident
2 that Solar Choice customers will have the proper information and tools to
3 respond to a TOU rate design, including access to at least 12 months of
4 interval usage data, which will become increasingly available as the
5 deployment of advanced metering infrastructure (“AMI”) progresses.

- 6 3. Exported Energy: Solar Choice retains the existing retail rollover design
7 under the current NEM program and relies on TOU rates to provide
8 appropriate price signals to customers.

9 **Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION ON**
10 **THE IMPLEMENTATION OF A SOLAR CHOICE TARIFF FOR**
11 **DOMINION’S CUSTOMERS?**

- 12 A. The Solar Choice tariff should be made available for the longer of three years or
13 the final Commission approval of a successor tariff. As I discuss in more detail in
14 the body of my testimony, one of the critical deficiencies in Dominion’s proposal
15 is that it lacks support from a cost of service evaluation of residential and small
16 general service (“SGS”) solar customers. My recommended Solar Choice design
17 provides for near-term refinements to address these deficiencies that are
18 consistent with the general intent and objectives, as well as the specific directives,
19 contained in Act 62. These recommendations are intended to support the record
20 upon which the Commission may adopt a Solar Choice tariff in accordance with
21 Act 62.

22 In order to remedy the cost of service deficiency, Dominion should be
23 directed to conduct load research on Solar Choice customers and utilize that load

research to conduct an analysis of solar customers' cost of service. A minimum three-year availability window for initial version of Solar Choice should be sufficient to allow Dominion to conduct two years of load research to inform Solar Choice tariff updates, as appropriate.

II. DISCUSSION OF OVERARCHING ISSUES

A. Net Metering and Successor Best Practices

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANY'S SOLAR CHOICE TARIFF PROPOSAL AND HOW IT DIFFERS FROM NET METERING.

A. The Company's Solar Choice tariff proposal contains the following components, each of which I discuss in more detail throughout my testimony.

1. An increased BFC relative to the otherwise applicable tariff.
2. A credit rate for exports measured at 15-minute intervals set at the Company's proposed avoided cost rate as opposed to retail kWh rollover.
3. A requirement to take service under a Solar Choice TOU rate that differs materially from the Company's existing TOU rate offerings to residential and SGS customers.
4. A subscription charge under a capacity-based fee model, denominated as a \$/kW-AC of system capacity charge, with minimum capacity charges based on a 3 kW residential system and a 7.5 kW SGS system.

1 **Q. IS DOMINION’S PROPOSED SOLAR CHOICE TARIFF CONSISTENT**
2 **WITH SO-CALLED “BEST PRACTICES” IN NEM AND NEM**
3 **SUCCESSOR PROGRAMS THROUGHOUT THE COUNTRY?**

4 A. No. As I discussed in my testimony in the Generic Docket, Witness Everett’s
5 description of NEM best practices is inconsistent with most state NEM programs,
6 including those in jurisdictions that established a successor tariff regime. In that
7 proceeding I demonstrated several ways in which the information and conclusions
8 Witness Everett presented was at turns incorrect, incomplete, or otherwise based
9 on flimsy or non-existent evidence. In the instant proceeding, the Company
10 proposes a regime that contains features that have in some cases been adopted in
11 other jurisdictions, but amplifies and employs them in combination in a manner
12 that would produce the most punitive tariff in any state with a sizable on-site solar
13 industry. I also note that Witness Everett compounds the misleading nature of her
14 prior testimony on net metering best practices in the instant proceeding with
15 further inaccurate or misleading statements.

16 **Q. PLEASE EXPLAIN THE INACCURACIES OR MISLEADING**
17 **CHARACTERIZATIONS THAT YOU HAVE IDENTIFIED IN WITNESS**
18 **EVERETT’S DISCUSSION OF NEM BEST PRACTICES.**

19 A. Starting with inaccuracies, Witness Everett counts the state of New Hampshire as
20 a jurisdiction that has replaced NEM with net billing.³ This is simply incorrect.
21 New Hampshire’s NEM Alternative tariff continues to allow monthly netting of
22 nearly all components of a customer’s electricity bill. Only small line items for

³ Everett Direct at 5:6-7.

1 stranded costs and energy efficiency program charges are assessed on a gross
2 electricity supply basis. The most significant change that New Hampshire made in
3 establishing the NEM Alternative tariff is reducing the *carryover rate* for monthly
4 excess generation to exclude a portion (75%) of distribution charges.⁴ In other
5 words, customers are still permitted to net their energy usage within a monthly
6 period for most bill components.

7 Witness Everett also cites the states of Hawaii and Arizona as states that
8 have instituted net billing in place of traditional NEM.⁵ While this is true, it does
9 not make their DG solar policies comparable to what the Company has proposed.
10 For instance, despite very high levels of customer-sited DG penetration in Hawaii
11 – at an order of magnitude larger than what is present in South Carolina – Hawaii
12 has not introduced separate fixed charges, minimum bills, or subscription charges
13 for new customer-sited generation customers. Furthermore, it has gone to great
14 lengths to establish further tariff options designed to retain significant value and
15 provide actionable price signals to solar customers while also addressing specific
16 conditions on the isolated island grids that prompted a need to dissuade customers
17 from exporting power during low load periods. These include a Customer Self-
18 Supply Tariff (no exports), a Smart Export Tariff (designed to reward exports

⁴ New Hampshire Public Utilities Commission. Docket No. DE 16-576. Order No. 26,029. June 23, 2017, p. 2, *available at*: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/ORDERS/16-576_2017-06-23_ORDER_26029.PDF.

⁵ Everett Direct at 5:6-7.

1 from 4 PM – 9 AM), and a Grid-Supply Plus Tariff (export allowed with grid
2 support technology).⁶

3 Turning to Arizona, the state’s Resource Proxy Comparison (“RCP”) rate
4 for exports is in no way comparable to Dominion’s proposed export compensation
5 as part of its proposed Solar Choice tariff. The Arizona RCP design utilizes a 10-
6 year rate lock-in based on the year in which a project is installed, and the rate may
7 not decline by more than 10% annually.⁷ The lock-in period and limits on annual
8 reductions are both specifically intended to mitigate the potential negative impacts
9 on the DG industry that would be associated with future rate uncertainty and a
10 potential large decline in the value of on-site generation to prospective DG
11 customers.

12 For instance, Dominion proposes a rate of roughly 3.5 cents/kWh for
13 exports, in addition to an additional fixed charge and subscription charge. In
14 comparison, during the first year of RCP implementation in Arizona, the export
15 rate in Arizona Public Service (“APS”) territory was 12.9 cents/kWh. Even now,
16 the current rate of 10.45 cents/kWh will remain in place through September 30,
17 2021.⁸ In fact, due to concerns about economic impacts due to the COVID-19
18 pandemic, the Arizona Corporation Commission deferred a reduction in the RCP
19 rate scheduled to take effect September 30, 2020 for a year.

⁶ See Hawaiian Electric Company. Private Rooftop Solar Rate Options, *available at*: <https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/private-rooftop-solar>.

⁷ Arizona Public Service. Rate Rider RCP, *available at*: https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Residential/Renewable-Plans-and-Riders/rcp_RateSchedule.ashx?la=en.

⁸ *Id.*

1 **Q. PLEASE DESCRIBE WHAT YOU MEAN BY THE TERM “EXPORT”**
2 **AND ANY RELATED TERMS YOU USE IN YOUR TESTIMONY.**

3 A. “Export” refers to energy exported from a customer’s DG system in various
4 contexts depending on how the customer is compensated for that energy –
5 whether on a kWh credit basis or a monetary basis – depending on the program
6 and the netting interval. In the simplest form, “exported” energy is energy
7 produced by the DG system but not consumed immediately on-site by the
8 customer (*i.e.*, “exported” to the grid). By contrast a “net export” refers to a
9 measurement that takes place over some period of time, such as a month or a year.
10 It is important to appreciate this distinction in the context of the relevant DG
11 program though for the purposes of comparing how the Company proposes to
12 treat “exports” in its Solar Choice proposal with how exports are treated under the
13 current NEM program in South Carolina, NEM successor programs in other states
14 and my recommendations for the Solar Choice program in South Carolina.

15 In the context of the current NEM program in South Carolina, exported
16 energy refers to “net export” at the end of the applicable billing period (*i.e.*, the
17 end of the month). In other words, exports that are not consumed directly by the
18 customer within the month offset energy delivered by the utility to the customer
19 (*i.e.*, “imported” energy) at a 1:1 kWh ratio. If at the end of the month, the
20 customer has exported more energy than it imported, the customer bill is reduced
21 accordingly and the customer carries kWh-denominated “credits” for the amount
22 of the net export to the following month. I refer to that carryover as “rollover”,
23 which allows net kWh exports during a month to offset kWh usage during a

1 subsequent month at the same rate (*i.e.*, retail monthly rollover). So, at present
2 South Carolina has net metering with retail monthly rollover.

3 By contrast, the Company's Solar Choice proposal would eliminate
4 monthly retail netting and rollover and replace it with a regime that places a
5 monetary value on all exports (*i.e.*, no monthly netting) and applies that value as a
6 monetary credit to the customer's bill at the end of the month. I describe this as
7 "monetary crediting for all exports." As I discuss further below, other states' net
8 metering successor programs apply variations of "monthly retail netting and
9 rollover" and "monetary crediting for all exports"; but none apply the monetary
10 crediting for all exports in the dramatically punitive manner proposed by the
11 Company.

12 **Q. HOW DOES THE COMPANY'S PROPOSED SOLAR CHOICE**
13 **PROGRAM SPECIFICALLY COMPARE TO NET METERING**
14 **SUCCESSOR REGIMES ADOPTED IN OTHER JURISDICTIONS?**

15 A. Taken together, the Company proposes changes that are much more far-reaching
16 and detrimental than successor regimes adopted in a number of some of the higher
17 penetration solar markets. Table 1 lists attributes of several of these successor
18 regimes in comparison to the Company's proposed Solar Choice tariff, with
19 Dominion listed at the bottom of the table. As shown in Table 1, while a number
20 of the jurisdictions check off one or more "boxes" in terms of setting special
21 conditions for DG service, none cover nearly as much ground as Dominion's
22 Solar Choice proposal or include changes to so dramatically reduce the solar

value proposition for customers as Dominion seeks (e.g., the amount and basis of a proposed subscription charge).

Table 1: Comparison of NEM Successor Attributes

State/Utility	TOU	Special Solar Rate	Added Fixed Charge	Added Minimum Bill	Capacity Fee	Excess Generation Credit Practice
AZ (APS)	Yes	No	No	No	\$0.93/kW (avoid with demand rate)	Monetary export rate for all exports (10% limit on annual decline and 10-year rate lock-in)
AZ (TEP)	No	No	No	No	No	Monetary export rate for all exports (10% limit on annual decline and 10-year rate lock-in)
CA	Yes	No	No	No	None	Retail by TOU period
HI	No	No	No	No	No	Monetary export rate for all exports
MA	No	No	No	Potentially (on-peak only)	No	Retail less public purpose charges
NH	No	No	No	No	None	Retail less 75% of distribution rate
NY	No	No	No	No	\$0.69 - \$1.09/kW (public purpose)	Retail rate
NV	No	No	No	No	No	Monthly rollover at 75% of retail rate ⁹
TX (EPE)	No	No	No	\$18.25 - \$21.75 (avoid with demand rate)	No	Monthly credit at avoided costs
VT	No	No	No	No	No	Average retail rate + adders
SC (DESC)	Yes	Yes	\$10.50	Via fixed charge & GAC	\$5.40/kW	Avoided cost for all exports

Q. PLEASE EXPLAIN WHY YOU LIMITED TABLE 1 TO WHAT YOU REFER TO AS “HIGH PENETRATION” STATES.

A. There are two main reasons. First, states with relatively higher net metering penetration offer a better comparison to South Carolina than those with lower

⁹ Current rate. Successor started at 95% and declined in accordance with installed capacity benchmarks. See Section III(a) for a more detailed description.

1 penetration rates because they represent states where the DG industry is larger and
2 therefore has a more significant economic impact. In other words, they are
3 jurisdictions where the potential negative economic impacts of a transition to a
4 NEM successor program may have influenced decisions even if evaluations did
5 not expressly consider economic impacts as Act 62 requires the Commission to
6 do.

7 Second, including jurisdictions with lower DG penetration rates that have
8 in some cases adopted highly punitive DG compensation regimes would be
9 incomplete without also including other jurisdictions, including those with sizable
10 DG penetration (*e.g.*, New Jersey, Maryland), that continue to offer traditional
11 retail net metering without additional conditions or charges.

12 **Q. TABLE 1 CONTAINS A NARRATIVE DESCRIPTION OF THE**
13 **CREDITING PRACTICE FOR EXPORTED GENERATION. CAN YOU**
14 **PROVIDE A COMPARISON OF HOW THESE PRACTICES COMPARE**
15 **TO DOMINION'S SOLAR CHOICE TARIFF PROPOSAL IN NUMERIC**
16 **TERMS?**

17 A. Yes. Table 2 lists the approximate amounts of the *minimum* effective
18 compensation rate for residential customer-generator exports within a monthly
19 period for the previously identified states, along with the monthly rollover rate
20 where it varies from the rate applied to in-month exports. For several states I have
21 included more than one utility to illustrate the more or less typical rate. The
22 minimums reflect the lower tier or seasonal rates, exclude certain surcharges, and

– for the California utilities – reflect off-peak periods. Dominion is listed at the bottom of the table.

Table 2: NEM Successor Export Compensation

State/Utility	Netting and Rollover Method*	Within-Month Export Rate Minimum (cents/kWh) ¹⁰	Monthly Net Exports Rate (cents/kWh)
AZ (APS)	All-export rate	10.45	N/A
AZ (TEP)	All-export rate	8.68	N/A
CA (PG&E)	Monthly approximate retail rollover	24.4	Same
CA (SDG&E)	Monthly approximate retail rollover	21.5	Same
HI (HECO)	All-export rate	10.1	N/A
MA (Eversource East)	Monthly approximate retail rollover	21.5	Same
MA (NGrid)	Monthly approximate retail rollover	21.5	Same
NH (Eversource)	Monthly rollover at retail minus 75% distribution	15.2	11.4
NY (NGrid)	Monthly retail rollover	10.6	Same
NY (CHE)	Monthly retail rollover	14.7	Same
NV (NPC)	Monthly rollover at 75% retail	10.3	7.7
NV (SPPC)	Monthly rollover at 75% retail	8.6	6.4
TX (EPE)	Monthly rollover at avoided cost	10.1	2-3
VT	Monthly approximate retail rollover	15.4	Same
Dominion SC	All-export rate at avoided cost	3.6	N/A

As clearly indicated by Table 2, Dominion’s proposed rate for export compensation falls well below effective compensation rates under other successor designs that use an export rate, as well as those that rely on the retail rate in one form or another to determine the effective compensation rate.

¹⁰ A “within-month” export refers to any export to the grid. Unless a rate is listed as an “all-export rate” in the Netting and Rollover Method column customers are permitted to net imports and exports to the grid over a monthly billing period and are only billed for monthly net usage.

1 **Q. WHAT GUIDANCE DO THE EXAMPLES YOU HAVE PROVIDED**
2 **OFFER WITH RESPECT TO NEM SUCCESSOR BEST PRACTICES?**

3 A. They point to incremental and measured approaches that seek to balance the
4 competing objectives of ratemaking in general as well as the dual concerns
5 surrounding adverse impacts on non-participating customers and the economic
6 vitality of the customer-sited solar industry. As I discussed in my testimony in the
7 Generic Docket, these competing objectives are well represented in the guidance
8 provided by Act 62, which requires a balancing act between elimination of
9 identified cost shifts and avoiding industry disruption.

10 They also illustrate that numerous individual aspects of Dominion's approach to
11 Solar Choice design are disfavored. Those disfavored aspects include:

- 12 1. Eliminating netting entirely in favor of avoided cost for all exports.
- 13 2. Subjecting solar customers to a separate TOU rate not used for any other
- 14 customers.
- 15 3. Establishing additional fixed charges applicable only to solar customers.
- 16 4. Establishing highly punitive capacity-based surcharges applicable only to
- 17 solar customers.

18 **Q. DO YOU HAVE ANY CLOSING REMARKS TO THE COMMISSION ON**
19 **THE TOPIC OF NET METERING BEST PRACTICES?**

20 A. Yes. I want to emphasize the need for the Commission to appreciate the whole of
21 Dominion's proposal in the context of Act 62 and the place where South Carolina
22 now sits with respect to the magnitude and scale of any cost shifts that *might* exist
23 along with the beneficial economic impacts that the customer-sited solar industry

has brought to the state. Dominion's Solar Choice proposal represents, on the whole, the likely destruction of the customer-sited solar industry similar to that which took place in Nevada before being remedied by the Nevada Legislature, and in the territory of the Salt River Project ("SRP") in Arizona. I profiled both of these examples in my testimony in the Generic Proceeding, and I urge the Commission to consider them both as it evaluates the Company's proposal. On the same topic of the whole of the Company's proposal, I also refer the Commission to Section IV of my present testimony discussing the impacts of Solar Choice on customer solar economics and the misleading nature of the Company's testimony on the subject.

B. Solar Customer Cost of Service

Q. PLEASE BRIEFLY DESCRIBE HOW ACT 62 ADDRESSES SOLAR CUSTOMER COST OF SERVICE.

A. Act 62 only expressly mentions "cost of service" once, although there are multiple portions which contain implied references without using this specific term. With respect to the express mention, Act 62 requires the Commission's evaluation of the costs and benefits of the net metering program to consider:

the cost of service implications of customer-generators on other customers within the same class, including an evaluation of whether customer-generators provide an adequate rate of return to the electrical utility compared to the otherwise applicable rate class when, for analytical purposes only, examined as a separate class within a cost of service study.¹¹

Other portions of Act 62 address the related issue of costs shifts and subsidization, including a statement of intent regarding Solar Choice tariffs, and a

¹¹ Section 58-40-20(D)(2).

1 specific directive for Commission establishment of Solar Choice tariffs. These
 2 passages read as follows:

3 It is the intent of the General Assembly to: . . . (3) require the
 4 commission to establish solar choice metering requirements that
 5 fairly allocate costs and benefits to eliminate any cost shift or
 6 subsidization associated with net metering to the greatest extent
 7 practicable.¹²

8 In establishing a successor solar choice metering tariff, the
 9 commission is directed to: . . . (1) eliminate any cost shift to the
 10 greatest extent practicable on customers who do not have
 11 customer-sited generation while also ensuring access to customer-
 12 generator options for customers who choose to enroll in customer-
 13 generator programs; . . .¹³

14 Collectively these passages indicate that the costs to serve solar DG
 15 customers are an important factor, though not the only factor, in establishing
 16 reasonable Solar Choice tariffs. For instance, the use of the terms “cost shift” and
 17 “subsidization” are commonly used in ratemaking in reference to the results of a
 18 cost of service study. Furthermore, it is the Legislature’s intent that Solar Choice
 19 tariffs “fairly allocate costs and benefits” while the Commission’s evaluation of
 20 net metering costs and benefits must consider “the cost of service implications of
 21 customer-generators on other customers within the same class, including an
 22 evaluation of whether customer-generators provide an adequate rate of return to
 23 the electrical utility compared to the otherwise applicable rate class.”

¹² Section 58-40-20(A)(3).

¹³ Section 58-40-20(G)(1).

1 **Q. DOES ACT 62 REQUIRE A UTILITY TO CONDUCT A COST OF**
2 **SERVICE ANALYSIS THAT EXAMINES SOLAR DG CUSTOMERS AS**
3 **A SEPARATE CLASS OF CUSTOMERS?**

4 A. Yes. The Commission cannot reach any conclusions about the existence or
5 magnitude of any cost shift or subsidy, or the adequacy of the rate of return to the
6 electric utility without the benefit of information provided by a cost of service
7 study that examines customer-generators as a separate class of customers. Stated
8 another way, the results of such a cost of service study provide a cost
9 responsibility benchmark from which to evaluate how a theoretical class of solar
10 customers compares with non-solar customers in order to identify whether a
11 subsidy or cost shift exists in the first instance.

12 **Q. WHY IS IT IMPORTANT FOR SUCH AN EVALUATION TO EXAMINE**
13 **SOLAR DG CUSTOMERS AS A SEPARATE CLASS?**

14 A. The presence of an on-site solar generation system influences a customer's load
15 shape which in turn affects the load shape of their otherwise applicable rate class
16 that ultimately determines the allocation of different types of costs. For instance, a
17 given class of customers benefits from having constituent customers that use less
18 electricity during peak periods, which results in a lower allocation of peak-driven
19 costs. If those customers with lower electric demand during peak hours are
20 removed from that class, the remaining customers in the class are allocated a
21 comparatively greater amount of peak-driven costs on a per customer basis,
22 producing higher average rates. As such, examining solar DG customers as a

1 separate “hypothetical” class allows us to understand how their presence in their
2 otherwise applicable class impacts other customers positively or negatively.

3 It also helps ensure that solar customers are not overcharged under a Solar
4 Choice tariff (*i.e.*, reverse the direction rather than mitigate or eliminate an
5 identified cost shift). A Solar Choice tariff could overcharge solar customers if it
6 does not take into account how the installation of solar changes their cost of
7 service under accepted cost causation determinants, resulting in a utility achieving
8 a higher rate of return than the amount to which it is entitled.

9 **Q. WHAT ARE THE PRIMARY FACTORS THAT INFLUENCE THE**
10 **RESULTS OF A COST OF SERVICE EVALUATION OF DG SOLAR**
11 **CUSTOMERS RELATIVE TO NON-SOLAR CUSTOMERS?**

12 A. The primary factors are how solar affects a customer’s contribution to production,
13 transmission, and distribution costs. The cost of service study that Dominion
14 presented in its pending rate case allocates production and transmission embedded
15 costs based on class contributions to the annual system peak. The Company does
16 this by identifying the day on which the system peak occurred during the test year
17 and using the average class contributions to demands during a four-hour window
18 from 2 – 6 PM on that day. The day used for this coincident peak (“CP”) allocator
19 in the Company’s pending rate case is July 18, 2019.

20 For distribution costs the Company uses a non-coincident peak (“NCP”)
21 allocator based on the non-simultaneous peak demands of each class regardless of
22 when they occurred during a year. The NCP allocators differ from the CP
23 allocator in that different classes could experience their peaks during different

hours, months, or seasons whereas the CP allocator is based on class demands during a single common set of hours.

Q. PLEASE EXPLAIN HOW CUSTOMER-SITED SOLAR AFFECTS THE ALLOCATION OF COSTS THAT USE THE CP ALLOCATOR.

A. Solar customers provide a considerable benefit to their respective classes for production and transmission demand-related costs because the timing of the peak matches well with good solar production. Table 3 shows residential solar production and the capacity factor at the time of the July 18, 2019 peak hour – the hour ending (“HE”) at 3 PM – for each individual hour in the four-hour band used in the CP allocator, and the four-hour average. The capacity factor is calculated using a total residential solar capacity of 52.26 MW, the amount that had been installed as of January 1, 2019.¹⁴

Table 3: Basis for CP Allocator

<i>July 18, 2019</i>	HE 15	HE 16	HE 17	HE 18	Average
Load (MW)	4714	4688	4593	4370	4591
Residential Solar (MW)	32	29	23	14	24
Capacity Factor	60.52%	55.09%	44.78%	26.62%	46.75%

The actual effect on costs allocated to the residential class is slightly different because if the residential solar contributions to the peak hour are eliminated (*i.e.*, a counterfactual scenario where there were no solar customers in the residential class), the peak hour would shift to August 13, 2019 to 3 – 4 PM.

While the peak load reduction amounts above are specific to the July 18, 2019 peak day, solar contributions to peak load reduction would be similar on any

¹⁴ Derived from Company response to ORS 1-11(b) and (c).

day that is likely to produce a system peak. Table 4 presents the average MW output and capacity factor during the hours from 2 – 6 PM for the four summer months on each of the top 5 peak load days for each month. In practice, based on 2019 load data the peak hour appears more likely to occur in July or August than June or September as the top 34 hours for the 2 – 6 PM window during 2019 were in either July or August. If the top 20 *hours* themselves are selected rather than the top 20 days the average capacity factor was 51.3% because 14 of the top 20 peak load hours occurred from 2 – 4 PM.

Table 4: Solar Capacity Factor During Summer CP Hours

Month	June	July	August	September	Average
Capacity Factor	47.9%	45.6%	42.2%	37.1%	43.2%

Q. PLEASE EXPLAIN HOW SOLAR WOULD AFFECT THE ALLOCATION OF COSTS THAT USE THE NCP ALLOCATOR.

A. Solar could have a meaningful impact, or it could have little or no impact depending on the timing of residential class NCP for 2019. The solar contribution to the NCP allocator could be more variable than it is for the CP allocator since it does not reflect interclass load diversity. I was unable to determine how solar would impact the NCP allocator for the most recent cost of service study because the cost of service materials made available by the Company do not contain the information necessary to make these calculations.

1 **Q. HAVE YOU BEEN ABLE TO QUANTIFY THE IMPACTS OF**
2 **RESIDENTIAL SOLAR ON EMBEDDED COST ALLOCATION TO THE**
3 **RESIDENTIAL CLASS?**

4 A. I have done so partially but I was not able to produce a complete impact estimate
5 with the available information. With the available information I was able to
6 estimate that had there been no residential solar on the Dominion system, the
7 costs allocated using the CP allocator (*i.e.*, production and transmission) to the
8 residential class would have been roughly 0.33% higher (47.07% vs. 46.74%). To
9 make this estimate I calculated a grossed up system peak demand and grossed up
10 class shares of that peak demand by adding back residential solar production (plus
11 losses) during the July 18, 2019 averaged over the 2 – 6 PM period used for the
12 CP allocator. Thus, the total peak demand and the residential class peak demand
13 were increased by roughly 27 MW. I held all other class demands constant and
14 recalculated the residential share of the peak, which was 0.33% higher.

15 This calculation can be used as a starting point for calculating the value to
16 the residential class of having constituent customers that install solar in monetary
17 terms by applying the adjusted allocation percentages to the associated revenue
18 requirements. The monetary class savings divided by the total amount of solar
19 production produces a \$/kWh amount that can be compared to the volumetric
20 amounts that solar customers avoided paying. The analysis can be confined to
21 demand-related costs because any costs that are classified as energy-related and
22 allocated based on total class energy use produce a net zero effect. In other words,
23 it is not possible for an embedded cost of service analysis to show a subsidy for

1 energy-related costs unless the allocation mechanism is time-differentiated. If
2 time-differentiated marginal costs are used as the basis for an energy-related
3 comparison the amounts can differ.

4 It is possible to illustrate the comparative impacts with a simple example.
5 In the Company's cost of service study, the residential class was allocated
6 approximately \$111.680 million in demand-related production expenses, which
7 translates to a rate of \$0.01353/kWh spread over total residential sales. The
8 revised allocator I describe above (*i.e.*, 0.33% higher) produces an allocation of
9 \$112.467 million, a difference of roughly \$787,000. Dividing this by total solar
10 production over the year from the systems used to calculate the contribution to
11 peak demand, this difference amounts to \$0.01159/kWh. Based on this calculation
12 the cost of service value is roughly 85.7% of the rate that these same solar
13 customers avoided paying, indicating that there could be a *modest* subsidy for this
14 particular set of costs.

15 **Q. IS THIS SAVINGS REFLECTED IN THE COMPANY'S 2019 COST OF**
16 **SERVICE STUDY?**

17 A. It is reflected in the same conceptual form but the numbers differ. The Company
18 applied a behind the meter ("BTM") solar subtractor to its peak load allocator
19 calculations of 35 MW for the residential class and 4 MW for the SGS class.¹⁵
20 The derivation of these amounts is not made clear, but the higher peak reduction
21 used in the Company's materials appears to reflect an estimate based on systems
22 installed as of the peak day or some other date during 2019; whereas I made my

¹⁵ Company response to CCL-SACE 1-17 referring to the Company's response to DoD-FEA 1-22 in Docket No. 2020-125-E. Attachment titled "2019 System Peak Worksheet".

1 calculations based on systems installed as of January 1, 2019. I used the capacity
2 installed as of January 1, 2019 data because my calculation requires full annual
3 solar production from a known amount of solar capacity in order to produce an
4 effective cost of service solar value rate.

5 **Q. PLEASE EXPLAIN WHY YOU WERE NOT ABLE TO FULLY**
6 **EVALUATE THE COST OF SERVICE VALUE THAT SOLAR**
7 **CUSTOMERS PROVIDE TO THE RESIDENTIAL CLASS**

8 A. In this case I was not able to fully reconstruct the cost of service value of
9 residential solar to the residential class because the Company's cost of service
10 filings do not present a revenue requirement classified fully into production
11 demand, transmission demand, distribution demand, and customer-related revenue
12 requirements. The Company's filings also present only hard-coded output values
13 that do not allow changes in a primary allocator like CP that flow through to other
14 secondary allocators that are calculated dynamically within the study itself. A
15 complete analysis would require a reconstruction of the entire cost of service
16 study. Finally, as I noted above the available information was not sufficient to
17 reconstruct a modified NCP allocator.

18 **Q. WHAT INSIGHTS CAN THE COMMISSION GAIN FROM THIS**
19 **ILLUSTRATIVE EXAMPLE?**

20 A. The chief takeaway is that solar customers as constituents of a broader class can
21 provide considerable benefits to that class in the form of a reduction in the
22 allocation of embedded costs. However, I emphasize that the picture is incomplete

1 for the purpose of evaluating the cost of service value of solar under a Solar
2 Choice tariff for the following reasons:

- 3 • It does not reflect a full evaluation of all embedded costs.
- 4 • It does not incorporate the fact that a residential solar customer might have
5 a different average profile before installing solar from the average
6 residential customer.
- 7 • It does not account for the fact that the peak day could be different under a
8 counterfactual scenario where there is no residential solar on the system
9 reducing the peak.
- 10 • It is backwards looking at existing residential solar customers, therefore it
11 does not reflect how a Solar Choice tariff could affect solar customer cost
12 of service (*e.g.*, providing incentives for customers to reduce their
13 contribution to peak loads through means other than solar).

14 **Q. SHOULD THE COMMISSION CONSIDER THE RESULTS OF A COST**
15 **OF SERVICE STUDY THAT EXAMINES SOLAR DG CUSTOMERS AS A**
16 **SEPARATE CLASS FULLY DETERMINATIVE?**

17 A. No, for several reasons. First, cost of service results are generally recognized as a
18 useful guide in ratemaking rather than as a single exclusive factor in setting rates
19 given that ratemaking involves the consideration and balancing of numerous
20 factors. In addition, the results present only a backwards-looking snapshot that
21 does not capture the long-term avoided cost and other benefits of customer-sited
22 solar, or, as I observed above, how the results would change under a Solar Choice
23 tariff design that supports customer actions that reduce their cost of service. I note

1 in this respect I again note that my analysis is confined to the solar contribution to
 2 reducing a residential solar customer's cost of service. It does not incorporate the
 3 load side of the cost of service equation, which could show different results based
 4 on differences in how solar customer load profiles differ from an average
 5 customer profile before the contribution from solar is considered.

6 Finally, Act 62 expressly directs that the Commission seek to eliminate
 7 any identified cost shift "to the greatest extent practicable".¹⁶ As I observed in the
 8 Generic Docket, that language compels the Commission to consider the objectives
 9 and intent of Act 62 as a whole, such that "the greatest extent practicable" means
 10 measures that do not compromise a Legislative intent to:

- 11 • [B]uild upon the successful deployment of solar generating capacity
 12 through Act 236 of 2014 to continue enabling market-driven, private
 13 investment in distributed energy resources across the State reducing
 14 regulatory and administrative burdens to customer installation and
 15 utilization of onsite distributed energy resources.¹⁷
- 16 • [A]void disruption to the growing market for customer-scale distributed
 17 energy resources;¹⁸

18 Accordingly, to the extent that a complete cost of service evaluation
 19 suggests that a cost shift from non-customer-generators to customer-generators
 20 exists, Act 62 does not require it to be entirely eliminated if doing so would
 21 prevent the achievement of the above objectives.

¹⁶ Section 58-40-20(G)(1).

¹⁷ Section 58-40-20(A)(1).

¹⁸ Section 58-40-20(A)(2).

1 **Q. WHAT SORTS OF ELEMENTS WITHIN A SOLAR CHOICE TARIFF**
 2 **COULD HELP IMPROVE THE COST OF SERVICE RESULTS FOR**
 3 **SOLAR CUSTOMERS?**

4 A. TOU rates are one mechanism that can be used, provided that the time windows
 5 that govern the TOU price signal align with the determinants of cost allocation so
 6 as to incentivize customers to reduce their load or take other actions, such as
 7 discharging on-site storage during likely peak times. More targeted methods such
 8 as an air-conditioning cycling program, a dedicated energy storage demand
 9 response program, or a critical peak pricing (“CPP”) component within the TOU
 10 rate design could also be utilized for this purpose.

11 **III. SOLAR CHOICE TARIFF ELEMENTS**

12 **A. Export Rate Proposal**

13 **Q. PLEASE BRIEFLY SUMMARIZE DOMINION’S PROPOSAL FOR**
 14 **COMPENSATING SOLAR CHOICE CUSTOMERS FOR EXPORTED**
 15 **GENERATION.**

16 A. The Company proposes to provide Solar Choice customers with a credit at its
 17 proposed avoided costs for exports as measured over 15-minute intervals.¹⁹ The
 18 proposed avoided cost rates a slightly differentiated into seasonal on-peak and
 19 off-peak periods within a range of 3.6 – 3.8 cents/kWh.²⁰

20 **Q. IS THE COMPANY’S PROPOSAL REASONABLE?**

21 A. No. As I previously demonstrated, a transition from the current retail netting
 22 regime to an avoided cost export credit regime is contrary to best practices that

¹⁹ Company response to ORS 1-4.

²⁰ Everett Direct at 47, Table 11.

1 have been employed in other states to address the same purported cost-shift issues
2 faced by the Commission here. Furthermore, as discussed by other parties in the
3 Generic Docket, the proposed rate does not reflect a complete analysis of the
4 long-term benefits of customer-sited solar. Again, I want to emphasize for the
5 Commission that as illustrated in my testimony in the Generic Docket and in
6 Table 1 above on net metering successor best practices, netting over the course of
7 a month remains the prevailing methodology in most jurisdictions.

8 **Q. WHAT OPTIONS ARE AVAILABLE TO THE COMMISSION FOR**
9 **ALIGNING EXPORT COMPENSATION WITH THE BENEFITS OF**
10 **THAT EXPORTED GENERATION?**

11 A. The adoption of a requirement for Solar Choice customers to take TOU rate
12 service would provide an improvement in the accuracy of the price signal, both
13 from the standpoint of the value of solar generation as well as how a customer
14 uses that generation. Beyond this improvement, there are several options for
15 modifying how exported generation is treated if such modifications are deemed
16 necessary. The Commission's options are therefore as follows:

- 17 1. TOU With Retail Netting and Retail Rollover: Rely on the retail TOU rate
18 to provide the correct price signals for both load and exports and retain the
19 annual netting regime.
- 20 2. Public Purpose Non-Bypassable Charges ("NBCs"): Retain a general retail
21 credit for exports regime across months, but do not permit netting for
22 specific charges, such as public purpose programs like demand-side
23 management ("DSM"), and instead require customers to pay for public

purpose programs based on gross imports from the grid just as non-solar customers do (*e.g.*, California, New Hampshire).

3. Monthly Retail With Subtractor: Retain monthly netting, with or without an exclusion of targeted charges, and reduce the monthly rollover credit to an amount different from the retail rate, such as a percentage of the retail rate (*e.g.*, Nevada) or to exclude a portion of designated retail charges (*e.g.*, New Hampshire).

4. Monthly Avoided Costs: Retain netting within a month and switch to avoided cost rate credit for monthly net excess generation. This is a fairly common approach used for net metering generally in states throughout the country.²¹

5. Proxy Export Rate: Designate a rate for all exports to the grid (*i.e.*, no meaningful netting period) in an amount that is determined by a method other than a utility's avoided cost rate (*e.g.*, Arizona, Hawaii).

Q. WHICH OF THESE OPTIONS WOULD BE THE MOST REASONABLE FOR THE COMMISSION TO ADOPT FOR DOMINION'S SOLAR CHOICE TARIFF?

A. At present I recommend that the Commission select Option #1 to retain the annual netting methodology for several reasons. First, Dominion failed to produce a cost of service study that evaluates solar customers as a separate class, and has therefore failed to meet its burden of demonstrating that a change is necessary. Second, Option #1 retains a NEM framework that is readily understandable to

²¹ See, for example, Everett Direct in the Generic Docket.

1 both customers and solar providers and can be implemented seamlessly by
2 Dominion. Third, the time-varying price itself provides a consistent signal that
3 treats load reductions and the additional exports that may be produced by load
4 reductions at different times equally, which avoids the potential for creating
5 mixed or conflicting incentives based on whether or not such reductions would
6 produce an export of customer-generated energy. Such mixed signals could send
7 the wrong signal by incentivizing customers to increase on-peak usage of flexible
8 loads (or simply not reduce it) in order to avoid forfeiting some of the value of on-
9 peak exports.

10 **Q. DO YOU HAVE ANY FURTHER RECOMMENDATIONS TO THE**
11 **COMMISSION REGARDING THE EXPORT COMPENSATION**
12 **METHODOLOGY?**

13 A. Yes. Should the Commission reach a conclusion that the exports regime requires
14 further refinement beyond that offered by TOU rates with retail netting, I
15 recommend that it consider Options #2 or #3 as the most suitable for meeting the
16 requirements of Act 62. Option #2, like Option #1, retains the general character of
17 retail rollover, but can be used to address specific deficiencies in customer
18 payments towards certain costs that are not fully offset by other benefits, and
19 which require recurring and consistent funding, such as a public benefit program
20 (*i.e.*, DSM programs).

21 Option #3 contemplates an administratively-determined reduction in the
22 effective monthly rollover rate that can be used to mitigate any unreasonable
23 amount of subsidy, should the Commission determine such a subsidy exists under

the retail NEM structure, while also meeting Act 62's objectives of avoiding disruption of the customer-sited solar industry, building on the success of Act 236, and considering economic impacts in its evaluation of the costs and benefits of net metering. For the purpose of Option #3 I recommend the approach used by Nevada when it reinstated NEM under 2017 A.B. 405. A.B. 405 provides for a progressive reduction in the monthly rollover rate as a percentage of the retail rate for new systems of 25 kW or less as certain capacity benchmarks (*i.e.*, tiers) are reached. A customer is qualified to receive service under the applicable capacity tier for 20 years after they enroll in NEM. The applicable retail rate excludes public purpose charges. The specific design is as follows:²²

- Tier #1 (80 MW): 95% of retail
- Tier #2 (80 MW): 88% of retail
- Tier #3 (80 MW): 81% of retail
- Tier #4 (uncapped): 75% of retail

Q. PLEASE ELABORATE ON HOW THE NEVADA A.B. 405 APPROACH IS IN ALIGNMENT WITH ACT 62.

A. By tying gradual, incremental adjustments to the rollover rate for monthly net excess generation to achievement of installed capacity thresholds, the A.B. 405 design effectively accounted for the market impacts of these rate changes and reversed the disruptive impacts wrought on the industry from the dramatic NEM program changes instituted prior to its enactment. The graduated nature of the system and the establishment of 20-year legacy rights provide both customers and

²² See NV Energy. Net Metering 405 (NMR-405) Opt-in, *available at*: <https://www.nvenergy.com/account-services/energy-pricing-plans/net-metering/nmr-405>.

1 solar providers with the certainty they need to consider long-term personal and
2 business financial planning.

3 **Q. PLEASE EXPLAIN WHY YOU DO NOT RECOMMEND**
4 **CONSIDERATION OF OPTIONS #4 AND #5.**

5 A. I do not recommend Option #4 because the avoided cost rate does not reflect the
6 full long-term value of customer-sited solar generation as contemplated by Act
7 62, and fails to provide the flexibility afforded by Option #3 as it relates to
8 meeting the broad objectives of Act 62. I do not recommend Option #5 because it
9 represents a significant departure from a NEM-based framework that is readily
10 understandable for customers and providers, and would require customers to have
11 access to historic interval usage data in order to make accurate predictions of solar
12 savings. Furthermore, designing an export rate method of the types employed in
13 Arizona and Hawaii raises a multitude of design questions that there is inadequate
14 time to explore fully.

15 **B. TOU Rate Proposal**

16 **Q. PLEASE BRIEFLY SUMMARIZE THE COMPANY'S SOLAR CHOICE**
17 **TOU RATE PROPOSAL.**

18 A. The Company proposes a Solar Choice TOU rate with the following time
19 windows for both residential and SGS customers.²³

- 20 • Peak Summer: 4 – 8 PM from June through September.
- 21 • Peak Winter: 5 – 9 AM from December – February.

²³ Everett Direct at 40:1-6.

- Off Peak: all other hours, including weekends (Saturday and Sunday) and holidays.

These time windows differ from the windows established under the Company's existing residential and SGS TOU rate options. The residential non-demand TOU rate (Rate Schedule 5) uses a peak period from 2 – 7 PM (M-F) from June – September and 7 AM – 12 PM (M-F) from October – May. The SGS TOU rate (Rate Schedule 16) uses a peak period from 1 – 9 PM (M-F) from June – September and 6 – 10 AM and 6 – 10 PM (M-F) from October – May.

Q. WHAT DESIGN FACTORS DID THE COMPANY EXAMINE WHEN DEVISING ITS PROPOSED SOLAR CHOICE TOU RATES?

A. Company Witness Everett states that she examined the average pattern of costs by hour and month and then “visually determined groupings of hours to develop TOU periods, with the qualification that each TOU period should be four hours and occur over no less than three consecutive months.”²⁴ The visualization is shown in a “heat map” presented as Figure 7 in her testimony. Witness Everett also states that “[a] four-hour peak, creates a large differential between peak and off-peak periods, which creates a greater incentive for customers to modify behavior for a manageable period of time.”²⁵

²⁴ *Id.* at 39:3-7.

²⁵ *Id.* at 39:7-9.

1 **Q. DOES THE COMPANY’S EXISTING RESIDENTIAL TOU RATE MEET**
2 **THE FOUR HOUR DURATION AND THREE CONSECUTIVE MONTHS**
3 **QUALIFYING CRITERIA THAT WITNESS EVERETT APPLIED?**

4 A. Yes. As I previously noted Rate Schedule 5 contains a peak period from 2 – 7 PM
5 (M-F) from June – September and 7 AM – 12 PM (M-F) from October – May.
6 The on-peak period duration is five (5) hours all year, with seasonal durations of
7 four (4) months for the summer period and eight (8) months for the winter period.

8 **Q. HOW DOES THE RATE SPREAD UNDER EXISTING RATE SCHEDULE**
9 **5 COMPARE TO THE RATE SPREAD UNDER THE COMPANY’S**
10 **PROPOSED RESIDENTIAL SOLAR CHOICE TOU RATE?**

11 A. Rate Schedule 5 has significantly higher rate spreads. The rate spread under Rate
12 Schedule 5 is roughly 18.2 cents/kWh during the summer and 15.5 cents/kWh
13 during the winter. Under the residential Solar Choice tariff proposal, the rate
14 spread is roughly 10.0 cents/kWh during the summer and 11.7 cents/kWh during
15 the winter. Therefore, the rate spread under Rate Schedule 5 is 8.2 cents/kWh
16 higher during the summer and 3.8 cents/kWh higher during the winter.
17 Accordingly, Rate Schedule 5 provides a greater incentive for customers to
18 modify their usage behavior than the proposed Solar Choice tariff even though it
19 features peak periods with a longer duration over more months of the year.

1 **Q. HOW COMPARATIVELY WELL DO THE RATE SCHEDULE 5 AND**
2 **THE PROPOSED SOLAR CHOICE ON-PEAK WINDOWS PERFORM**
3 **WITH RESPECT TO ALIGNMENT TO THE SYSTEM PEAK DEMANDS**
4 **USED TO ALLOCATE PRODUCTION AND TRANSMISSION COSTS**
5 **VIA THE CP ALLOCATOR?**

6 A. Both rates include non-summer peak periods that are not aligned with the CP
7 allocator. With respect to summer on-peak periods, Rate Schedule 5 has a better
8 alignment than the proposed Solar Choice summer peak window. Figures 1 and 2
9 below illustrate this in the form of a comparison of the average 2019 peak load by
10 month and by hour in reference to the single-hour 2019 peak (*i.e.*, as a percentage
11 as shown in Figure 1) and showing the hours where this percentage exceeded 80%
12 (shaded with a 1 as shown in Figure 2). The Rate Schedule 5 hours are outlined in
13 bold and the proposed Solar Choice hours are outlined with dash marks.²⁶ Also
14 recall that the 2019 peak hour was July 18 at HE15, which falls within the Rate
15 Schedule 5 summer on-peak period but not within the proposed Solar Choice
16 summer on-peak period, and that the CP allocator uses a 2 – 6 PM average on the
17 peak day.

²⁶ Figures 1 and 2 were calculated based on Company's response to ORS 1-11(b).

Figure 1: Heat Map of 2019 Peak Hourly Loads

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	53%	52%	52%	52%	54%	58%	63%	65%	64%	62%	60%	58%	56%	54%	54%	53%	54%	57%	61%	61%	61%	59%	57%	55%
2	46%	45%	45%	46%	47%	50%	55%	57%	56%	55%	54%	53%	52%	51%	50%	50%	51%	52%	55%	56%	55%	53%	50%	47%
3	44%	43%	44%	45%	47%	52%	55%	55%	54%	53%	51%	50%	49%	49%	48%	48%	49%	50%	52%	54%	52%	50%	47%	45%
4	41%	40%	40%	41%	43%	47%	48%	50%	51%	51%	52%	53%	54%	55%	56%	56%	56%	56%	55%	56%	54%	50%	47%	44%
5	49%	47%	46%	46%	47%	50%	52%	55%	59%	63%	67%	70%	73%	75%	77%	78%	77%	75%	72%	70%	67%	62%	57%	53%
6	52%	50%	49%	48%	49%	51%	53%	57%	61%	66%	69%	73%	76%	78%	80%	80%	80%	78%	75%	72%	70%	65%	60%	55%
7	57%	55%	53%	53%	54%	55%	57%	62%	67%	72%	77%	81%	85%	87%	88%	88%	87%	85%	82%	78%	76%	70%	65%	61%
8	57%	55%	53%	53%	54%	56%	58%	61%	65%	70%	75%	79%	82%	85%	86%	86%	85%	83%	80%	78%	74%	69%	64%	60%
9	51%	50%	48%	48%	49%	53%	53%	56%	59%	64%	68%	73%	77%	80%	81%	82%	81%	78%	76%	73%	69%	63%	59%	54%
10	45%	44%	43%	44%	45%	49%	51%	52%	53%	55%	57%	59%	61%	63%	64%	64%	64%	63%	63%	61%	57%	53%	49%	47%
11	48%	47%	47%	47%	49%	51%	56%	57%	57%	56%	54%	53%	52%	51%	51%	51%	52%	54%	57%	56%	56%	54%	52%	49%
12	49%	48%	48%	48%	49%	52%	57%	58%	58%	57%	55%	54%	52%	51%	51%	51%	52%	55%	57%	57%	57%	55%	53%	51%

Figure 2: 2019 Hours Averaging Above 80% of System Peak Load

Month/Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Q. WHAT WOULD RESULT FROM A MISALIGNMENT OF PEAK HOURS WITH THE METHODS USED FOR COST ALLOCATION?

A. Solar Choice customers would receive an inaccurate price signal which would fail to encourage them to act in a way that reduces the allocation costs to their broader rate class. For instance, if a Solar Choice customer waited until 4 PM to reduce their load they would at a minimum miss part of the peak window. Furthermore, a customer responding to the Solar Choice price signal might even shift some demand to the 2 – 4 PM period (e.g., pre-cooling a home in advance of the on-peak period). In doing so they would increase residential class load during these hours and cause additional costs to be allocated to the residential class.

1 **Q. SHOULD CUSTOMERS THAT TAKE SERVICE UNDER THE SOLAR**
2 **CHOICE TARIFF BE SUBJECT TO A SPECIALLY-DESIGNED TOU**
3 **RATE?**

4 A. To the extent that Solar Choice tariff customers are subject to a TOU rate
5 requirement, they should be permitted to take service under an otherwise available
6 rate. An existing TOU should be presumed to provide an accurate reflection of
7 cost of service, otherwise it should not be offered at all, and I have demonstrated
8 that the summer on-peak period contained in Rate Schedule 5 is superior to the
9 proposed Solar Choice rate with respect to alignment with the Company's cost of
10 service methodology,

11 Furthermore, devising a significantly different TOU rate structure
12 specifically for solar customers raises the appearance of discriminatory intent. If
13 the Company believes that its existing TOU rate structures do not provide good
14 price signals it has a much larger problem on its hands and should conduct a
15 broader review of its rates.

16 **Q. DO YOU RECOMMEND THAT SOLAR CHOICE CUSTOMERS BE**
17 **OBLIGATED TO TAKE SERVICE UNDER A TOU RATE?**

18 A. I believe that this would be a reasonable step to take, but the Commission should
19 also consider whether customers would have the information necessary to
20 effectively transition to a new rate design (*e.g.*, well-crafted outreach and
21 guidance, historical time-differentiated usage data). Accordingly, I recommend
22 that the Commission delay mandatory TOU as a condition of Solar Choice service
23 until a customer has access to at least 12 months of interval usage data.

C. Basic Facilities Charge Proposal

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSAL FOR SETTING THE BFC UNDER THE SOLAR CHOICE TARIFF.

A. The Company proposes a BFC set at \$19.50/month for residential Solar Choice customers and \$32.50/month for SGS Solar Choice customers. These amounts are derived from the costs the Company classified as "customer-related" in the cost of service study filed in its most recent rate case.²⁷ The proposed BFCs are actually rounded from amounts of \$19.49/month for residential customers and \$32.64/month for SGS customers that were presented in the rate case.²⁸ The Company's rationale for setting the Solar Choice BFCs at these amounts is that these are fixed costs that are driven by the number of customers rather than their energy needs or demands.²⁹

Q. DID THE COMPANY PROPOSE BFCS SET AT THESE AMOUNTS IN ITS RATE CASE?

A. No. It proposed to set the BFC at \$11.50/month for customers taking service on the standard residential rate (Rate 8) and \$15.50/month for residential customers taking service under one of the TOU rate options (Rates 5 and 7). For SGS customers it proposed a BFC of \$22.00/month for the standard SGS rate (Rate 9) and \$25.65/month for the generally available SGS TOU rate options (Rates 16 and 28).³⁰

²⁷ Rooks Direct at pp. 6-7.

²⁸ See Docket No. 2020-125-E. Direct Testimony of Allen W. Rooks, Exhibit AWR-2. September 4, 2020.

²⁹ Everett Direct at 35:13-14.

³⁰ *Id.*

1 **Q. HOW ARE THE CUSTOMER-RELATED COSTS FROM THE**
2 **COMPANY’S RATE CASE COST OF SERVICE STUDY CALCULATED?**

3 A. The Company states that it defined customer-related costs to include meters and
4 metering expenses, customer accounting and sales expenses, investment and
5 expenses for customer service drops, investments and expenses associated with
6 the secondary distribution system, and a portion of investment and expenses
7 associated with secondary line transformers.³¹ The secondary portion of the
8 distribution system except for line transformers is listed as exclusively customer-
9 related. This includes all secondary poles, overhead lines, underground lines, and
10 underground conduit contained in the Federal Energy Regulatory Commission
11 (“FERC”) Uniform System of Accounts 364-367. For secondary line transformers
12 (FERC Account 368) the customer-related portion of secondary transformer plant
13 is designated as roughly 41.8% for the residential class and 29.2% for the SGS
14 class.³² The other components I mentioned above (*e.g.*, metering, customer
15 accounting) are designated as exclusively customer-related.

16 **Q. IS THE COMPANY’S METHOD FOR CLASSIFYING COSTS AS**
17 **CUSTOMER-RELATED AND SETTING THE SOLAR CHOICE BFCS**
18 **APPROPRIATE?**

19 A. No. The Company’s calculated customer-related unit costs inappropriately
20 include costs associated with the shared secondary distribution system that should
21 be classified as demand-related. As I previously testified to before the
22 Commission in the Duke Energy affiliates’ most recent rate cases, and other

³¹ See Docket No. 2020-125-E. Direct Testimony of Kevin R. Kochems, at 16:8-12. September 4, 2020.

³² *Id.* Exhibit KRK-1, p. 3.

parties have testified to in the Company's pending rate case, customer-related costs are properly limited to those that vary directly with customer numbers, such as metering, customer services, and billing. All components of the shared distribution system should be considered demand-related. The Company's classification of *all costs* in FERC Accounts 364-367 associated with the secondary distribution system as customer-related is particularly inappropriate.

Furthermore, despite the Company's assertion that a significant portion of the shared secondary distribution system is customer-related, the cost of service study indicates that those costs are allocated based on customer NCP demands, referred to as "Billing Demand at the Customer Level (Secondary)" or the C35 allocator.³³

In other words, these shared distribution system costs are in fact reflected as demand-related costs according to the Company's cost of service study. To remove all doubt, the actual basis for those allocators bears this demand-related treatment out as shown in Table 5 below.³⁴

Table 5: Secondary Distribution Cost Allocators

Allocator Name	Service Class	Amount	Allocation %
CUST C35	GSL	0	0.00%
CUST C35	GSM	441,397	6.17%
CUST C35	GSS	1,355,858	18.95%
CUST C35	RS	5,287,180	73.90%
CUST C35	STL	69,904	0.98%
CUST C35	WHS	0	0.00%

³³ Company response to ORS 1-5, attaching its response to ORS 2-40 in Docket No. 2020-125-E showing the allocators used in its cost of service study.

³⁴ Company response to CCL-SACE 1-17 referring to the Company's Supplemental response to DoD-FEA 1-22 in Docket No. 2020-125-E. Attachment titled "Cost of Service Inputs".

Clearly, the amount column in Table 5 does not represent customer numbers given that Dominion does not have more than five million residential customers, or more than 400,000 medium general service class customers.

Q. IS IT COMMON FOR THE DEFINITION OF CUSTOMER-RELATED COSTS TO BE LIMITED TO COSTS THAT VARY DIRECTLY WITH CUSTOMER NUMBERS?

A. Yes. This is the accepted method in many states. A 2000 report developed by the Regulatory Assistance Project (“RAP”) and published by the National Association of Regulatory Utility Commissioners (“NARUC”) found that this Direct or Basic Customer Method, which classifies distribution plant in FERC Accounts 364-368 as 100% demand-related was the most common approach at the time of the report:

There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states.³⁵

³⁵ F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 29, REGULATORY ASSISTANCE PROJECT (2000), available at: <http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724>.

1 **Q. CAN THE COMMISSION RELY ON THIS REPORT AS AN ACCURATE**
2 **ASSESSMENT OF DISTRIBUTION COST CLASSIFICATION AND**
3 **RATE DESIGN AT THE TIME IT WAS AUTHORED?**

4 A. Yes. The list of authors is composed of several former utility regulators, including
5 several former commissioners, each of which held positions on various NARUC
6 boards and committees.³⁶

7 **Q. WHY DO YOU CONSIDER THE DESIGNATION OF ALL NON-**
8 **TRANSFORMER SECONDARY DISTRIBUTION COSTS AS CUSTOMER-**
9 **RELATED TO BE “PARTICULARLY INNAPPROPRIATE”?**

10 A. Even if one accepts that there are some shared distribution system costs that are
11 properly classified as customer-related, it is necessary to conduct further analysis
12 to determine the customer-related proportion. The Company has done so for
13 secondary line transformers, but failed to do so for the other portions of the
14 secondary system. Such a division is commonly accomplished through either a
15 minimum system or zero-intercept analysis. However, the simple designation of
16 the entire secondary portion of the distribution system as customer-related is not
17 an accepted method of defining customer-related costs in any regulatory
18 jurisdiction that I am aware of.

19 Furthermore, the Company’s designation of plant as serving the secondary
20 rather than primary distribution function is strangely large, making the impact of
21 the inappropriate classification regime correspondingly larger. At the total retail

³⁶ See the RAP website for biographies of the principal author Frederick Weston (former Vermont Public Service Board Economist and Hearing Officer) and contributors David Moskowitz (former Maine Public Utilities Commission Commissioner) and Richard Cowart (former Vermont Public Service Board Chairman and Commissioner), *available at*: <https://www.raponline.org/about/>.

1 service level, the secondary function component of FERC Accounts 364-367 is
 2 roughly 42.7%.³⁷ It is more typical for the secondary component to be
 3 considerably lower. For instance, in Duke Energy Carolinas LLC's 2018 general
 4 rate case, the secondary distribution component of FERC Accounts 364-367 was
 5 roughly 18%. In Duke Energy Kentucky, Inc.'s 2017 rate case, the cost of service
 6 study showed a secondary distribution component for these collective accounts of
 7 roughly 25%.

8 **Q. CAN YOU POINT TO SPECIFIC EXAMPLES WHERE THE BASIC**
 9 **CUSTOMER METHOD HAS BEEN ENDORSED FOR USE OR IS**
 10 **OTHERWISE USED IN COST OF SERVICE STUDIES OR FOR THE**
 11 **PURPOSE OF ESTABLISHING FIXED CHARGES?**

12 A. Yes. In 2015, legislators in Connecticut directed the Public Utilities Regulatory
 13 Authority ("PURA") to utilize the Basic Customer Method for the purpose of
 14 establishing a maximum residential customer charge.³⁸ Likewise, in 2018,
 15 regulators in Colorado directed Black Hills Energy to eliminate the minimum-
 16 intercept method³⁹ entirely from its cost of service study in the utility's most

³⁷ See Docket No. 2020-125-E. Direct Testimony of Kevin R. Kochems, at 16:8-12. Exhibit KRK-1, p. 3. September 4, 2020.

³⁸ Connecticut Public Act 15-5, June Special Session, *available at*: https://www.cga.ct.gov/asp/cgabillstatus/CGAbillstatus.asp?selBillType=Bill&bill_num=1502&which_year=2015. The act requires PURA to "adjust each electric distribution company's residential fixed charge ... to recover only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service."

³⁹ The minimum intercept method is one type of analysis that utilities sometimes use to define a customer-related portion of the shared distribution system.

1 recent general rate case.⁴⁰ Most recently, in a proceeding on grid modernization,
 2 the New Hampshire Public Utilities Commission made the following finding:

3 Customer Charges: We find that customer charges should only be
 4 used to recover customer-related costs as identified in a cost of
 5 service study. Such costs include the cost of the ratepayer-funded
 6 investments required to serve the customer, which in the
 7 Commission's experience for residential customers are typically
 8 identified as the service drop, the portion of the meter directly
 9 related to billing for usage, and the costs of billing and collection.⁴¹

10 Other states where the practice of defining a customer-related component for
 11 shared distribution infrastructure has been expressly rejected for use in cost
 12 allocation or for the purpose of establishing customer charges include Texas⁴² and
 13 California.⁴³ I am also aware that the cost of service studies used by Public
 14 Service New Mexico, Rocky Mountain Power in Utah, the Potomac Electric
 15 Power Company and Baltimore Gas & Electric in Maryland, Entergy New
 16 Orleans, Appalachian Power in Virginia, and Entergy Arkansas do not define any
 17 shared distribution costs as customer-related.

18 Finally, a letter from the Washington Utilities and Transportation
 19 Commission ("WUTC") to NARUC regarding the publication of the NARUC
 20 Electric Utility Cost Allocation Manual ("NARUC Manual") indicates that
 21 WUTC staff believed the Basic Customer Method to be the most common

⁴⁰ Colorado Public Utilities Commission. Docket No. 17AL-0477E. Decision No. C18-0445. June 15, 2018, *available at*: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=887641.

⁴¹ New Hampshire Public Utilities Commission. Docket No. 15-296. Order No. 26,358. May 22, 2020, *available at*: https://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/ORDERS/15-296_2020-05-22_ORDER_26358.PDF.

⁴² Public Utilities Commission of Texas. Docket No. 22344. Order No. 40, p. 6. November 22, 2000.

⁴³ California Public Utilities Commission. Docket No. A.16-06-013. Decision No. 17-09-035. p. 33 and 40. September 28, 2017. The decision allows a portion of final line transformer costs consistent with a minimum-sized transformer to be included in a fixed charge.

1 approach to establishing customer-related costs throughout the country, citing
2 Arizona, Iowa, and Illinois as states that have explicitly rejected the practice of
3 defining customer-related costs to include components of the shared distribution
4 system.⁴⁴

5 **Q. TO SUMMARIZE, HOW MANY STATES HAVE YOU CITED THAT**
6 **HAVE ENDORSED THE BASIC CUSTOMER METHOD OR**
7 **OTHERWISE USED IT IN A COST OF SERVICE STUDY OR FOR THE**
8 **PURPOSE OF ESTABLISHING A FIXED CHARGE?**

9 A. The number of states totals 14 (plus the City of New Orleans) including the five
10 states that have explicitly rejected the inclusion of shared distribution
11 infrastructure as customer-related costs, five additional states referred to in the
12 context of utility cost of service studies, and four more referred to by the WUTC
13 letter (including Washington). In fact, there are even more states that utilize low
14 customer charges that could only be arrived at by taking a narrow view of costs
15 that are reasonable to include in BFCs, such as New Jersey, Michigan, and Idaho,
16 and Massachusetts.

17 **Q. WHY IS THE BASIC CUSTOMER METHOD PREFERRED IN MANY**
18 **STATES FOR THE PURPOSE OF SETTING FIXED CHARGES?**

19 A. There are several reasons. As I have already described, regulators in many states
20 do not accept the conceptual idea that there is a customer-related aspect of the
21 shared distribution system at all. Apart from that core reason, ratemaking requires

⁴⁴ WUTC. Docket No. UE-170002. December 3, 2018 Technical Workshop presentation, Attachment 2, available at: https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=56&year=2017&docKetNumber=170002.

1 a balance of competing objectives and thus there are typically multiple
2 contributing factors. For instance, states that prioritize energy efficiency and
3 demand reduction tend to utilize lower fixed charges, often derived using the
4 Basic Customer Method, because high fixed charges reduce incentives for
5 customers to modify their consumption behavior by lowering the charges for non-
6 fixed rate components.

7 Economic efficiency (*i.e.*, discouraging wasteful use of service) is also a
8 common consideration. Economic efficiency is supported by rate designs that are
9 based on marginal costs. The basic customer method approximates the marginal
10 cost of adding a new customer to the system because it reflects only the costs that
11 are directly related to the number of customers, not the demand-related costs that
12 arise from a customer's use of the shared system up to the level of their *full*
13 *demand*.

14 **Q. HAS THE COMMISSION ENDORSED USING THE COMPANY'S**
15 **METHOD OF SETTING BFCS BASED ON THE DIRECT**
16 **TRANSLATION OF CUSTOMER-RELATED UNIT COSTS FROM A**
17 **UTILITY COST OF SERVICE STUDY?**

18 A. To my knowledge the Commission has never indicated that BFCs should be based
19 on cost of service study unit costs even where it has accepted a cost of service
20 study that, for instance, ascribes a customer-related component to the shared
21 distribution system as a basis for allocating costs. Again, I also reiterate here that
22 the derivation of class allocators for secondary distribution system in the
23 Company's cost of service study is actually demand-based rather than customer-

1 based. Furthermore, I note that the Company's customer-related unit cost
 2 calculation and derivation of a so-called "cost-based" BFC remains a point of
 3 disagreement with multiple parties in its rate case.⁴⁵

4 Finally, even when the Commission has accepted a cost of service study,
 5 the actual adopted class revenue allocations typically differ from the results
 6 produced by the cost of service study. Consequently, it is not accurate to equate
 7 acceptance of such study with an endorsement of using it exclusively to define
 8 class allocations. Rather, for both revenue and allocation and rate design, the
 9 study only functions as a starting point which is modified in consideration of
 10 balancing other ratemaking principles. In other words, the study results are not
 11 "determinative" in the manner that the Company seeks to use them for Solar
 12 Choice tariff design.

13 **Q. HOW DOES ACT 62 ADDRESS THE ROLE OF ENERGY EFFICIENCY**
 14 **DEMAND RESPONSE, AND CUSTOMERS' ABILITY TO CONTROL**
 15 **THEIR ELECTRIC BILLS?**

16 A. Act 62 contains several pieces of highly relevant language. First, Section 2 of Act
 17 62, enumerated in Article 7, Chapter 27, Title 58 Section 58-27-845 makes the
 18 following statement:

19 (A) The General Assembly finds that there is a critical need to:

20 (1) protect customers from rising utility costs;

⁴⁵ See Commission Docket No. 2020-125-E. Surrebuttal Testimony of David Dismukes on behalf of the South Carolina Department of Consumer Affairs, December 18, 2020; and Direct Testimony of Scott J. Rubin on behalf of SC AARP, November 10, 2020.

(2) *provide opportunities for customer measures to reduce or manage electrical consumption from electrical utilities in a manner that contributes to reductions in utility peak electrical demand and other drivers of electrical utility costs; and*

(3) *equip customers with the information and ability to manage their electric bills.*

(B) *Every customer of an electrical utility has the right to a rate schedule that offers the customer a reasonable opportunity to employ such energy and cost-saving measures as energy efficiency, demand response, or onsite distributed energy resources in order to reduce consumption of electricity from the electrical utility's grid and to reduce electrical utility costs.*

(C) In fixing just and reasonable utility rates pursuant to Section 58-3-140 and Section 58-27-810, the commission shall consider whether rates are designed to *discourage the wasteful use of public utility services* while promoting all use that is economically justified in view of the relationships between costs incurred and benefits received, and that no one class of customers are unduly burdening another, and that each customer class pays, as close as practicable, the cost of providing service to them.

(D) For each class of service, the commission must ensure that each electrical utility offers to each class of service a minimum of *one reasonable rate option that aligns the customer's ability to achieve bill savings with long-term reductions in the overall cost the electrical utility will incur in providing electric service,* including, but not limited to, time-variant pricing structures.

(emphasis added)

Q. DOES ACT 62 PROVIDE OTHER DIRECTION TO THE COMMISSION THAT IS RELEVANT TO SETTING BFCS FOR SOLAR CHOICE TARIFFS?

A. Yes. Act 62 expressly requires that Solar Choice tariffs “permit solar choice customer-generators to use customer-generated energy behind the meter without

1 penalty.”⁴⁶ Establishing a different BFC for Solar Choice customers based on a
2 method of setting the BFC that differs markedly from the methods used to set
3 BFCs for other customers amounts to discrimination, penalizing such customers
4 solely based on the presence of customer-sited generation.

5 **Q. IS THE COMPANY’S PROPOSAL FOR A HIGHER BFC ON SOLAR**
6 **CHOICE TARIFF CUSTOMERS CONSISTENT WITH THESE**
7 **PORTIONS OF ACT 62?**

8 A. No. The Company’s proposal conflicts with all of these findings and
9 requirements, in particular when one considers the Company’s proposed Solar
10 Choice subscription charge which also effectively establishes a significant
11 additional fixed charge on participating customers. I discuss the subscription
12 charge elsewhere in my testimony, but the Commission should appreciate that it
13 amounts to a fixed charge that significantly decreases a customer’s incentive and
14 ability to achieve bill savings by modifying their consumption in a manner that
15 produces long-term system benefits.

16 **Q. WHAT ARE YOUR RECOMMENDATIONS TO THE COMMISSION**
17 **FOR SETTING THE BFC IN DOMINION’S SOLAR CHOICE TARIFFS?**

18 A. First, in order to be non-discriminatory and meet the Act 62 requirement that
19 successor solar choice tariffs not penalize users of customer-sited generation
20 systems, the BFC should be based on the rates charged to similarly situated non-
21 participant customers. Given that that Solar Choice tariff would eventually require
22 TOU metering, the proper benchmark are the BFCs charged to residential

⁴⁶ Section 58-40-20(G)(2).

1 customers that take service on Rates 5 and 7 and SGS customers that take service
2 on Rates 16 and 28. As proposed in the Company's rate case, this would result in
3 BFCs of \$15.50/month for residential Solar Choice customers and \$25.65/month
4 for SGS Solar Choice customers.

5 However, I also recommend that these amounts take the form of minimum
6 bills rather than BFCs for Solar Choice customers for two reasons. First, they
7 derive from a future mandatory TOU rate requirement rather than a fully
8 discretionary customer election. In this context, any incremental TOU metering
9 costs are caused at least in part by the design of the Solar Choice tariff rather than
10 Solar Choice customers. Second, the amounts of the Company's truly customer-
11 related costs are in dispute in the Company's pending rate case. The amounts I
12 propose for the minimum bill represent a rough midpoint between the proposed
13 generally applicable residential and SGS BFCs and the Company's disputed
14 designation of its customer-related unit costs.

15 A minimum bill in the amounts I propose strikes the right balance between
16 ensuring that customers pay their fair share of customer-related costs and
17 minimizing the impact that the higher charge has on other avoidable charges that
18 form the basis for customer control over their energy bills and their ability to
19 benefit from modifying their usage in ways that produces long-term system
20 benefits. Thus, under the rate case proposed rates, a residential Solar Choice
21 customer would pay a BFC of \$11.50/month and a \$15.50/month minimum bill
22 while an SGS Solar Choice customer would pay a BFC of \$22.00/month and a

1 \$25.65/month minimum bill. The BFC would count towards the payment of this
2 minimum bill.

3 **D. Subscription Charge Proposal**

4 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED SOLAR CHOICE**
5 **SUBSCRIPTION CHARGE.**

6 A. The Company proposes a subscription charge based in the installed capacity of a
7 Solar Choice system in the amount of \$5.40/kW for residential customers with a
8 minimum monthly charge of \$16.20, and \$6.50/kW for SGS customers with a
9 minimum monthly charge of \$48.75.⁴⁷ The minimum amounts are based on a 3
10 kW-AC residential system and a 7.5 kW-AC SGS system.

11 **Q. HOW ARE THE AMOUNTS FOR THE SUBSCRIPTION CHARGE**
12 **DERIVED?**

13 A. The Company employs a calculation that starts with the amount that a customer
14 would pay towards transmission and distribution costs prior to the installation of a
15 reference solar system. From these amounts the Company subtracts an amount
16 calculated based on its proposed avoided costs multiplied by the estimated
17 amount of annual electricity from the reference solar system that would be
18 consumed behind the meter. Company Witness Everett's Tables 6 and 7 show
19 these amounts for residential and SGS customers. For example, for residential
20 customers the transmission and distribution revenue requirement is listed as
21 \$339/year, while the avoided cost subtraction is \$146/year, leading to a
22 subscription charge amount of \$193/year. This amount is then divided by the

⁴⁷ Everett Direct at 44:6-14.

1 reference system minimum system size, which is 3 kW for residential customers
2 to produce an annual \$/kW charge which is then translated to a monthly amount
3 (*i.e.*, $\$193 \div 3 \text{ kW} \div 12 \text{ months} = \$5.36/\text{kW}/\text{month}$, rounded to $\$5.40/\text{kW}/\text{month}$).

4 **Q. HOW DOES THE DESIGN OF THE PROPOSED SUBSCRIPTION**
5 **CHARGE OPERATE IN PRACTICE?**

6 A. It effectively charges Solar Choice customers for electricity that they produce and
7 consume directly behind the meter because its foundation lies in a misguided and
8 unfounded notion that a “subsidy” is created any time customer generation
9 displaces energy that would have otherwise been purchased from the Company. It
10 is effectively the same as levying an additional charge on customers that reduce
11 their electricity consumption by installing LEDs or more efficient appliances.

12 **Q. IS THE SUBSCRIPTION CHARGE CONSISTENT WITH COST**
13 **CAUSATION PRINCIPLES?**

14 A. No. The Company’s proposal is based on a supposed responsibility that solar
15 customers bear for embedded transmission and distribution costs. However, that
16 cost responsibility can only be identified by conducting an embedded cost of
17 service study of solar customers, which the Company did not do. As I previously
18 demonstrated, customer solar generation affects both the CP and class NCP
19 allocators that the Company uses to assign cost responsibility to customer classes,
20 reducing the amount of costs assigned to a respective class for both.

1 **Q. IS THE SUBSCRIPTION CHARGE CONSISTENT WITH ACT 62**
 2 **REQUIREMENTS FOR SOLAR CHOICE TARIFFS?**

3 A. No. Act 62 expressly requires that Solar Choice tariffs “permit solar choice
 4 customer-generators to use customer-generated energy behind the meter without
 5 penalty.”⁴⁸ The subscription charge is specifically designed to charge Solar
 6 Choice customers for electricity that they produce and consume directly behind
 7 the meter. It could not be more directly or completely in violation with this
 8 portion of Act 62.

9 **Q. HAVE SUBSCRIPTION CHARGES BEEN EMPLOYED IN NET**
 10 **METERING SUCCESSOR TARIFFS IN OTHER JURISDICTIONS?**

11 A. Yes, but not in a manner that is similar to what the Company proposes. In
 12 Arizona, APS now imposes a Grid Access Charge of \$0.93/kW-DC on residential
 13 solar customers that do not take service under one of the time-varying demand
 14 rate options.⁴⁹ This is clearly a far more modest charge than what Dominion
 15 proposes. When coupled with the standard monthly fixed charge (\$12.99/month),
 16 a residential APS solar customer with a 7.2 kW-DC system would pay a fixed
 17 monthly charge of \$19.69/month for the combined BFC and Grid Access Charge,
 18 which is roughly equivalent to what Dominion proposes for the residential BFC
 19 by itself (\$19.50/month). I also note that the Arizona Corporation Commission
 20 rejected proposals from sister utilities Tucson Electric Power and Unisource
 21 Energy Services to establish solar-specific rate designs due to deficiencies in the

⁴⁸ S.C. Code Section 58-40-20(G)(2).

⁴⁹ APS Rate Schedule TOU-E (Saver Choice). <https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Residential/Service-Plans/SaverChoice.ashx?la=en>.

1 companies' solar customer cost of service studies.⁵⁰ Thus, unlike APS, neither
2 utility has been permitted to employ a similar charge to this point.

3 New York has established a Customer Benefit Contribution ("CBC")
4 charge under a capacity fee design for residential customers that take net metering
5 service beginning in 2022. The CBC is intended to ensure that customers who
6 take net metering service pay in sufficient amounts towards public benefit
7 programs, such as solar rebate and energy efficiency incentive programs from
8 which they benefit. The residential amounts vary by utility from \$0.69/kW -
9 \$1.09/kW depending on the utility.⁵¹

10 In both cases the charges are far more modest and accomplish more
11 reasonable objectives than what Dominion has proposed. The APS Grid Access
12 Charge is oriented around costs associated with distribution facilities located in
13 close proximity to the customer, which Dominion has already proposed be
14 included within the BFC. The New York CBC provides a means of collecting
15 revenue to support programs that solar customers may participate in and benefit
16 from and which cannot be avoided by the installation of customer-sited solar.

17 **Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION**
18 **REGARDING THE PROPOSED SOLAR CHOICE SUBSCRIPTION**
19 **CHARGE?**

20 A. The subscription charge should be rejected in its entirety because it is in direct
21 conflict with Act 62, fails to comport with cost causation principles, and is not

⁵⁰ Arizona Corporation Commission. Docket No. E-01933A-15-0322. Decision No. 76899. September 20, 2018, *available at*: <https://docket.images.azcc.gov/0000192323.pdf?i=1611164861104>.

⁵¹ New York Public Service Commission. Case No. 15-E-0751. July 16, 2020, *available at*: <https://tinyurl.com/y4hbffqo>.

1 consistent with good practice, design, and objectives of subscription-type fees as
2 they have been employed in other jurisdictions.

3 **Q. WOULD IT BE REASONABLE FOR THE COMMISSION TO ADOPT**
4 **ANY FORM OF CAPACITY-BASED CHARGE ON SOLAR CHOICE**
5 **CUSTOMERS?**

6 A. No. While I have described two other examples of capacity-based charges
7 implemented in other jurisdictions' NEM successor tariffs, neither would be
8 appropriate to follow in this case because other portions of my recommended
9 Solar Choice design already address the respective use cases. First, the BFCs that
10 the Company has proposed in its rate case would already raise revenue in excess
11 of its actual customer-related costs and I have recommended a minimum bill
12 slightly above those amounts. This approach effectively includes a portion of
13 demand-related distribution costs for facilities located in close proximity to the
14 customer in the minimum bill. Although I disagree with the characterization of
15 any secondary distribution costs as customer-related, I believe that the moderate
16 incremental minimum bill I suggest could be a reasonable compromise. Second,
17 with respect to public purpose program charges, I have recommended that the
18 Commission consider any mitigation measures that it deems necessary to address
19 the issue in the context of the export compensation regime.

IV. SOLAR CHOICE IMPACTS ON SOLAR ECONOMICS

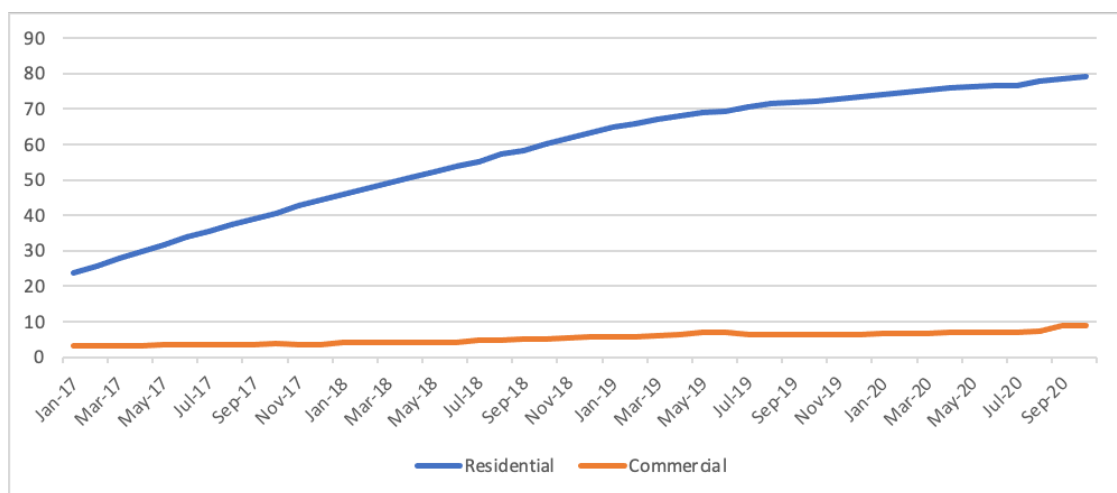
Q. HOW WOULD YOU DESCRIBE THE CURRENT TRENDS IN NEW NET METERING SYSTEM INSTALLATIONS IN DOMINION'S SERVICE TERRITORY?

A. Residential installation rates have slowed down fairly significantly during 2019 and 2020, while commercial installation rates remain small and slow, as they have been in the past. Figure 3 and Table 6 sourced from monthly EIA data illustrates these trends, in particular showing how the residential installation curve has been growing flatter over time.

Table 6: Average NEM Monthly Capacity Additions

Year	Residential Monthly Capacity Additions (MW)	Commercial Monthly Capacity Additions (MW)
2017	1.88	0.05
2018	1.58	0.16
2019	0.84	0.13
2020 (to Oct.)	0.57	0.13

Figure 3: Monthly NEM Capacity Additions Since 2017



1 I note that Company Witness Robinson made a similar observation in the
2 Generic NEM Docket.⁵² Company Witness Robinson also projected growth in net
3 metered installations in all sectors at 69 MW-AC from 2020-2030, comprised of
4 57.5 MW of residential installations and 11.5 MW of non-residential installations.
5 For comparison to Table 6, the residential installation rate associated with this
6 projection would be roughly 0.44 MW/month, which is below even the lowest
7 rate in actual installations set from January – October 2020.

8 **Q. DO TRENDS IN INSTALLATION RATES INDICATE ANYTHING**
9 **ABOUT THE ECONOMICS OF INSTALLING NET METERED SOLAR**
10 **SYSTEMS FROM THE STANDPOINT OF A CONSUMER?**

11 A. It suggests that the consumer value proposition appears less compelling than it
12 used to be even under the current net metering tariff and prevailing rates. While
13 consumers weigh a number of factors when making a decision to purchase or
14 lease a solar system, expected future energy cost savings is a significant
15 motivating factor.

16 **Q. ARE THERE ANY READILY IDENTIFIABLE REASONS WHY**
17 **INSTALLATION RATES MIGHT HAVE SLOWED IN RECENT YEARS**
18 **EVEN AS SYSTEM COSTS HAVE DECLINED?**

19 A. Yes. The federal tax credit stepped down from 30% in 2019 to 26% in 2020 for
20 both homeowner-owned and third-party owned systems. Perhaps more
21 significantly, the adjustments to Dominion's rates associated with the removal of
22 costs for the VC Summer plant have significantly reduced customer rates. For

⁵² Docket No. 2019-182-E. Direct Testimony of Scott Robinson at 11:14-18.

1 instance, effective in May 2017 Dominion's standard residential rate (Rate 8)
 2 carried a first tier (use up to 800 kWh) energy charge of 13.644 cents/kWh.⁵³ As
 3 of June 2020, the rate for the first tier under Rate 8 is 11.602 cents/kWh.⁵⁴ This is
 4 a decline of roughly 15%, which: (a) directly impacts projections of future
 5 savings, and (b) impacts consumer *perceptions* of the likelihood and magnitude of
 6 future utility rate increases.

7 In other words, as VC Summer costs increased rates customers became
 8 accustomed to progressive, significant rate increases, which in turn prompted
 9 consideration of ways to reduce higher energy bills that corresponded with
 10 increased rates. Currently, customers' most recent experiences are rate decreases
 11 so their perceptions and fears about future increases have likely responded
 12 accordingly and they are comparatively less motivated to install solar. This
 13 attitude may shift a bit in the other direction as rate increases associated with the
 14 Company's pending rate case take effect.

15 It is also possible that the COVID-19 pandemic has negatively impacted
 16 2020 installation numbers in a number of ways, such as making consumers
 17 generally more cautious given potential uncertainties about their employment and
 18 the economy, and more directly through complications associated with direct
 19 interactions between solar providers and prospective customers.

⁵³ South Carolina Electric & Gas. Rate Schedule 8 effective May 2017, *available at*:
<https://etariff.psc.sc.gov/Attachments/revisionChangesFile/cf8bbeb0-0e3d-44fd-bd1e-ba4b1ca4ea92>.

⁵⁴ Dominion Energy South Carolina. Rate Schedule 8 effective June 2020, *available at*:
<https://etariff.psc.sc.gov/Attachments/revisionChangesFile/012a0a19-65e2-459b-aa3e-a5b7cc77f8bc>.

1 **Q. HOW SHOULD THE COMMISSION CONSIDER THESE TRENDS AS IT**
2 **EVALUATES DOMINION’S SOLAR CHOICE TARIFF?**

3 A. The Commission should recognize that the solar installation market in
4 Dominion’s territory is already under considerable economic stress under the
5 current net metering regime. Changes to that regime that negatively impact
6 customer bill savings would exacerbate that distress. The changes that Dominion
7 seeks are severe to the point that they could effectively eliminate the customer-
8 sited solar industry in its territory.

9 **Q. HOW WOULD THE COMPANY’S SOLAR CHOICE PROPOSALS**
10 **AFFECT CUSTOMER SAVINGS ASSOCIATED WITH INSTALLING A**
11 **CUSTOMER-SITED SOLAR SYSTEM?**

12 A. The reduction in customer savings would be dramatic for systems that are sized to
13 offset a significant amount of a customer’s load. Witness Everett’s testimony does
14 not provide a numerical comparison of customer savings under the Solar Choice
15 tariff proposals, but the effects can be derived from her workpapers. Table 7
16 illustrates before solar and after solar bills under both net metering and the
17 Company’s proposed Solar Choice tariff for an average-sized residential and SGS
18 solar system and the average load profiles used by the Company. The Solar
19 Choice Before Offset row indicates a customer’s annual bill inclusive of the
20 Company’s proposed subscription charge. This amount is higher than a pre-solar
21 bill under tiered rates due to the collective elements of the Company’s proposed
22 Solar Choice tariff. The Net Solar Choice Savings row incorporates that bill

increase in conjunction with savings produced by a solar system under the Company's proposed Solar Choice design.

Table 7: Solar Choice vs. NEM Customer Savings

[BEGIN CONFIDENTIAL]

	Residential (7.2 kW)	SGS (18 kW)
Pre-Solar NEM⁵⁵		
Post-Solar NEM		
NEM Savings		
Solar Choice Before Offset⁵⁶		
Solar Choice After Offset		
Solar Choice Offset Savings		
Net Solar Choice Savings		
Solar Choice Net Difference (\$)		
Difference (%)		

[END CONFIDENTIAL]

Q. DO YOU AGREE THAT COMPANY WITNESS EVERETT'S MODELING APPROXIMATES THE DIFFERENCE IN CUSTOMER BILL SAVINGS UNDER NET METERING COMPARED TO SOLAR CHOICE?

A. The amounts reflected in Table 7 (based on information provided by the Company) are likely fairly close to the mark, but holding all else equal they would understate the reduction in savings because the reduction is sensitive to the amount of exports that a system produces. The amounts in Table 7 are based on an hourly profile whereas Solar Choice would calculate exports based on 15-

⁵⁵ Company response to NCSEA 1-5, Confidential Attachment 1, in tabs labeled CALC_CURRENT_BILLS.

⁵⁶ Company response to NCSEA 1-5, Confidential Attachment 1, in tabs labeled CALC_NEW_BILLS.

minute intervals, which results in a larger percentage of generation being deemed an export. The effect is visible in the example that the Company provided in response to an information request, which is pasted below.⁵⁷

Table 8: Solar Choice Netting Methodology Example

	Avg kW	Avg kW	Avg kW	Avg kW	kWh	
Interval	3:01-3:15	3:16-3:30	3:31-3:45	3:46-4:00	Total Measured Flows	Applicable Pricing for One-Hour Interval
Exported Power	1	1	0	0	0.5	TOU Credit
Consumed Power	0	0	1	1	0.5	TOU Rate

As is visible in Table 8, a one-hour netting interval would produce a zero net charge, resulting in customer savings valued at the retail TOU rate. A 15-minute interval for determining exports produces 0.5 kWh valued at the retail TOU rate and 0.5 kWh valued at the lower avoided cost rate.

Q. ARE THERE ANY OTHER FACTORS THAT WOULD CAUSE THE IMPACTS TO VARY?

A. Yes. They will vary predictably based on the relationship between system size and energy production to a customer's consumption, which I refer to as the load coverage ratio. Table 7 presents a residential system with a coverage ratio of 87.3% meaning that solar production equals 87.3% of total annual load. The SGS system has a coverage ratio of 86.4%. A lower coverage ratio will produce a smaller amount of exports and reduce the net impact of Solar Choice while a system sized at a higher coverage ratio (e.g., 100%) will experience a larger net

⁵⁷ Company response to ORS 1-4.

1 savings loss relative to NEM. It is important to note that a smaller system only
2 produces a smaller net negative impact if customer load size is left constant.

3 The impacts will also vary from customer to customer because an average
4 load profile is representative only of customers in aggregate rather than individual
5 customers or groups of customers. For instance, it would not be unusual for the
6 load shape of relatively lower usage customers to differ from that of relatively
7 higher usage customers (*e.g.*, a customer with electric heating is likely to be a
8 higher use customer with a different winter load shape than a non-heating
9 customer). Finally, system orientation would influence savings under both net
10 metering and Solar Choice both due to differences in total system production and
11 differences in the production shape that, alongside the load shape, influence the
12 amount and timing of exports.

13 **Q. DOES THE COMPANY PROVIDE ANY ANALYSIS OF HOW THE**
14 **SOLAR CHOICE TARIFF PROPOSALS WOULD IMPACT PROJECTED**
15 **INSTALLATION RATES RELATIVE TO THE PROJECTIONS IT**
16 **PROVIDED IN THE GENERIC DOCKET?**

17 A. No. The Company did not provide a projection for Solar Choice equivalent to
18 what it provided in the Generic Docket.

19 **Q. DOES THE COMPANY PROVIDE ANY ANALYSIS THAT PROVIDES**
20 **INDICATIONS OF THE POTENTIAL IMPACT ON CONSUMER**
21 **UPTAKE?**

22 A. Company Witness Robinson presents two metrics relevant to this question. One is
23 the simple payback, which for a cash-purchased system provides an easy to

1 understand measure of how long it takes customer savings to fully redeem the
2 initial cash outlay. The second is a levelized bill ratio, which essentially provides
3 an indication of whether a customer actually saves money by installing a solar
4 system, or instead pays a premium relative to what they would have otherwise
5 paid for electricity without the system.

6 The Company's evaluation presents an unrealistic picture of customer-
7 sited solar economics by both metrics. For instance, Witness Robinson estimates
8 that the simple payback for a residential system under the current net metering
9 regime is roughly seven years, with some variations based on system size.⁵⁸
10 Under the Solar Choice tariffs, he places the simple payback for a 3 kW
11 residential system installed in 2021 at 6.9 years in low-cost scenario, 8.9 years in
12 a mid-cost scenario, and 9.7 years in a high-cost scenario.⁵⁹ From a levelized bill
13 ratio standpoint, he estimates 2021 ratios for residential systems at 0.81 for the
14 low-cost scenario and about 0.87 for the mid-cost and high-cost scenarios and
15 observes that these ratios indicate that a customer would experience overall bill
16 savings because the ratios are less than 1.0.⁶⁰

⁵⁸ Robinson Direct at 11:8-10.

⁵⁹ *Id.* at 13:7-9

⁶⁰ *Id.* at 12:7-11.

1 **Q. PLEASE EXPLAIN WHY COMPANY WITNESS ROBINSON'S**
 2 **PROJECTIONS DO NOT PRESENT AN ACCURATE PICTURE OF HOW**
 3 **THE SOLAR CHOICE TARIFFS WOULD IMPACT CUSTOMER-SITED**
 4 **PV ECONOMICS.**

5 A. I have identified several aspects of those calculations that render them highly
 6 misleading and inaccurate. Before getting into the details of those specific
 7 problems, I first wish to point to the clear incongruity between the customer
 8 savings impacts presented by Company Witness Everett and those provided by
 9 Company Witness Robinson. Table 9 presents savings impact estimates for a 3
 10 kW residential system and a 7.5 kW SGS system using the same comparison
 11 methodology I used in Table 7 based on Company Witness Everett's modeling.

12 **Table 9: Solar Choice vs. NEM Customer Savings (Small System)**

13 [BEGIN CONFIDENTIAL]

	Residential (3 kW)	SGS (7.5 kW)
Pre-Solar NEM⁶¹		
Post-Solar NEM		
NEM Savings		
Solar Choice Before Offset⁶²		
Solar Choice After Offset		
Solar Choice Offset Savings		
Net Solar Choice Savings		
Solar Choice Net Difference (\$)		
Difference (%)		

⁶¹ Company response to NCSEA 1-5, Confidential Attachment 1, in tabs labeled CALC_CURRENT_BILLS.

⁶² Company response to NCSEA 1-5, Confidential Attachment 1, in tabs labeled CALC_NEW_BILLS.

[END CONFIDENTIAL]

As shown in Table 9 smaller systems relative to load size fare better under Solar Choice. In this scenario the load coverage ratio is 36.4% for the residential system and 36% for the SGS system. However, there are three important details associated with this difference. First, whereas the residential system still shows a fairly sizeable loss in the amount of customer savings, Witness Robinson's projections for simple payback indicate only the smallest difference. Table 10 shows the full simple payback results under the mid-cost and high-cost scenarios for systems installed in 2021 from Witness Robinson's workpapers for the same system sizes. It should be obvious that there is no world in which reducing customer bill savings by more than [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] can produce only a [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] year increase in the simple payback period.⁶³

Table 10: Robinson Simple Payback Estimates

[BEGIN CONFIDENTIAL]

	Residential Payback (Yrs)		SGS Payback (Yrs)	
Cost Scenarios	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Net Metering	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Solar Choice	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
Incremental Payback Period	[REDACTED]		[REDACTED]	

[END CONFIDENTIAL]

All other things being equal, a [BEGIN CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] decrease in bill savings would produce a [BEGIN

⁶³ Sourced from Dominion response to NCSEA 1-5, Confidential Attachment titled "ReSim_Custom_Export_12282020", tab labeled "Simple_Payback_Export".

1 CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL] year increase in the simple
2 payback period. Furthermore, one would expect the results for SGS customers to
3 be aligned with those for residential customers, but whereas Witness Everett's
4 calculations show a smaller net decrease in bill savings for SGS customers under
5 a small system scenario than residential customers, Witness Robinson's
6 calculations produce a larger incremental increase in simple payback.

7 Second, it is not system size by itself that produces these relatively better Solar
8 Choice outcomes for smaller-sized systems. The true differentiating factor is the
9 load coverage ratio. A 3 kW residential system installed by a customer with lower
10 than average consumption will fare worse than even Witness Everett's
11 calculations indicate. Finally, for both the residential and SGS profiles the Solar
12 Choice TOU rate design itself produces material bill savings even with the
13 additional fixed charge and an assumed subscription charge for a small system.
14 This could make the rate vulnerable to gaming by large customers that install
15 minimally-sized systems in order to gain access to a rate that is predisposed to be
16 preferential to them.

17 **Q. WHAT ARE THE PRACTICAL IMPLICATIONS OF A SOLAR CHOICE**
18 **DESIGN THAT PRODUCES DISPARATE IMPACTS ON CUSTOMER**
19 **SAVINGS DEPENDING ON THE LOAD COVERAGE RATIO?**

20 A. Customers with lower pre-solar loads will find the economics of solar to be much
21 more challenging than customers with higher pre-solar loads because a smaller
22 system will still cover a greater amount of their load. The market would be
23 steered towards high load customers that can install systems with low load

1 coverage ratios and eliminate a solar option for those that cannot. This could have
2 equity implications in terms of the availability of a cost-effective solar option for
3 low- to moderate-income customers.

4 **Q. IS IT POSSIBLE TO IDENTIFY WHY COMPANY WITNESS**
5 **ROBINSON'S PROJECTIONS OF THE IMPACTS OF SOLAR CHOICE**
6 **DIFFER FROM THOSE PRESENTED BY COMPANY WITNESS**
7 **EVERETT'S?**

8 A. At a high level the differences stem from differences in customer savings under
9 both net metering and Solar Choice between the two projections. For a 3 kW
10 residential system Company Witness Robinson projects lower savings under net
11 metering and higher savings under Solar Choice than Company Witness Everett
12 on a first-year basis. Furthermore, Witness Robinson's long-term projections
13 inflate Solar Choice savings over time at a greater rate than net metering savings,
14 to the point where Solar Choice savings actually become greater than net metering
15 savings. Table 11 shows Company Witness Everett's single-year estimates of
16 residential savings for a 3 kW system under net metering and Solar Choice
17 alongside the first-year and 20-year averages calculated by Company Witness
18 Robinson.⁶⁴

⁶⁴ Robinson estimates are sourced from Company response to NCSEA 1-5 Confidential Attachment titled "ReSim_Custom_Export_12282020", tab labeled "Cash_Flow_Export". Amounts for Everett correspond to those in Table 9.

Table 11: Solar Choice vs. NEM Savings Comparison

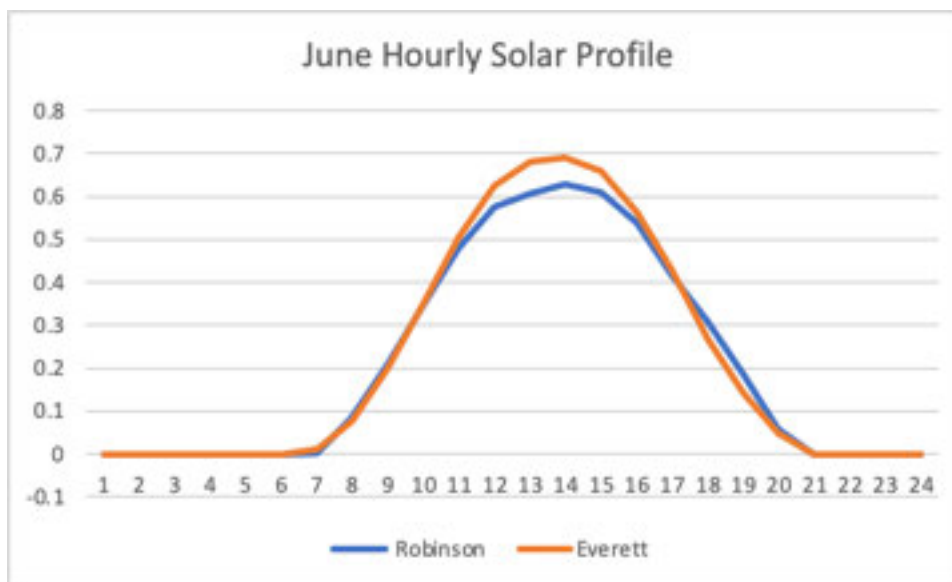
[BEGIN CONFIDENTIAL]

<i>3 kW Residential Savings</i>	Everett Single Year	Robinson 1st Year	Robinson 20-Year Avg.
Net Metering			
Solar Choice			
Difference (\$)			
Difference (%)			

[END CONFIDENTIAL]

Unfortunately, it is difficult to ascertain all of the reasons why the two Company Witnesses differ in their projections because Witness Robinson's workpapers provide hard-coded exported values from the underlying model rather than a complete self-contained set of calculations that allows the outputs to be traced based on underlying formulas. Having said that, one difference that appears to be a factor is that Witness Robinson uses a solar production profile with an annual per kW output of roughly 1,450 kWh whereas Witness Everett uses a profile with an output per kW of 1,642 kWh. Witness Robinson's profile is also shifted slightly to the right, indicating a more westward facing system orientation as shown in Figure 4 for the month of June.

Figure 4: Comparison of Solar Production Profiles



The lower solar production represented in the Robinson profile is at least part of the reason why his customer savings estimate under net metering is lower than Witness Everett's, and lower system production would also produce lower amounts of exports that become devalued relative to net metering under the proposed Solar Choice tariff.

Q. WHICH COMPANY WITNESS PROVIDES A MORE ACCURATE COMPARATIVE ASSESSMENT OF CUSTOMER SOLAR ECONOMICS UNDER NET METERING COMPARED TO SOLAR CHOICE?

A. As I previously noted, Company Witness Everett's calculations understate the reduction in customer savings because her calculations are based on hourly interval data to derive exports whereas the Company's proposed Solar Choice tariff would use a 15-minute interval. Apart from that important detail, while I am not endorsing every single aspect of Company Witness Everett's calculations, in

1 my review they present a far more accurate picture of the effects of Solar Choice
2 on solar economics than Witness Robinson's.

3 **Q. WHAT OTHER SPECIFIC PROBLEMS HAVE YOU IDENTIFIED WITH**
4 **WITNESS ROBINSON'S ANALYSIS OF HOW THE SOLAR CHOICE**
5 **TARIFF WOULD AFFECT THE ECONOMICS OF CUSTOMER-SITED**
6 **SOLAR?**

7 A. Beyond the issues of load coverage and differences in modeling between Witness
8 Everett and Witness Robinson, I take issue with several aspects of the system
9 costs assumptions Witness Robinson uses to calculate metrics such as payback
10 period and levelized bill ratios. Witness Robinson's assumptions significantly
11 understate system costs, and as a result he reaches erroneous conclusions on how
12 customer economics fare under both net metering and the Solar Choice tariffs.
13 The specific problems I have identified are as follows:

- 14 1. The system cost scenarios he uses are significantly lower than data from
15 other sources indicates is realistic.
- 16 2. The system cost assumptions assume that system size has no influence on
17 installed cost per watt.
- 18 3. The low-cost scenario should be entirely disregarded because it assumes
19 an *increase* in the federal ITC that is speculative at best, and unlikely in
20 reality, in addition to assuming unrealistic gross installed costs, as I have
21 noted in (1) above.

1 **Q. PLEASE ELABORATE ON WHY WITNESS ROBINSON’S INSTALLED**
 2 **COST ASSUMPTIONS ARE UNREALISTICALLY LOW.**

3 A. Company Witness Robinson uses a range of roughly \$2.40 - \$2.90/W-DC for
 4 residential systems in 2020 as a starting point for future installed cost
 5 projections.⁶⁵ The mid-cost scenario he employs uses a 2020 cost of [BEGIN
 6 CONFIDENTIAL] [REDACTED] [END CONFIDENTIAL].⁶⁶ This range of cost
 7 estimates, and even the high-cost scenario, is significantly below recent data on
 8 residential system costs.⁶⁷

9 As illustrated in Figure 5 below sourced from the Lawrence Berkeley
 10 National Lab Tracking the Sun Distributed Solar 2020 Data Update Report
 11 (“LBNL Report”), the median price for 2019 residential systems was roughly
 12 \$3.76/W-DC (shown as \$3.8/W-DC in the figure). The percentile band in Figure 5
 13 is based on the 20th and 80th percentile values, showing the middle 60% of prices
 14 with a range of \$3.05/W-DC to \$4.48/W-DC.⁶⁸ In other words, LBNL’s pricing
 15 data indicates that only 50% of systems in the sample were installed at a price of
 16 less than \$3.76/W-DC, and only 20% of systems in the sample were installed at a
 17 price of \$3.05/W-DC or less.

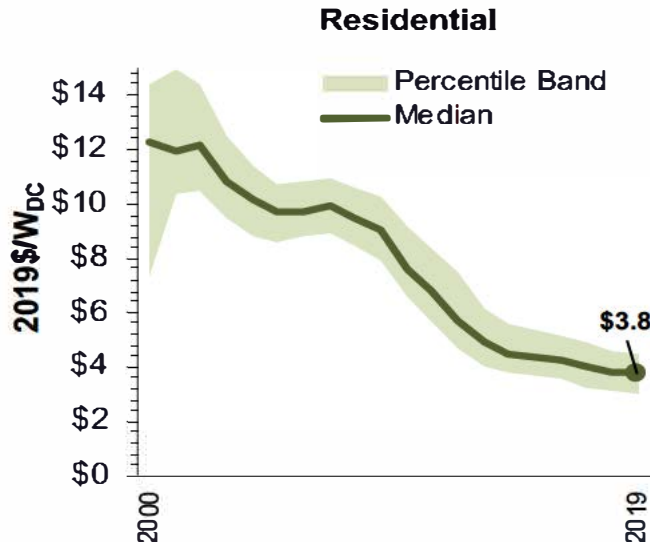
⁶⁵ Robinson Direct at 9:3-4.

⁶⁶ Company response to NCSEA 1-5, Confidential Attachment titled “Data Import Template ReSim – IRs, tab labeled “CostData”.

⁶⁷ I have limited my discussion of solar cost data to residential systems for the sake of simplicity but the same issues exist for non-residential system costs.

⁶⁸ LBNL Report. Summary Data Tables, tab labeled “Price Trends”. December 2020. Available at: <https://emp.lbl.gov/tracking-the-sun>.

Figure 5: Residential Installed Costs Over Time



It is also clear from Figure 5 that residential system pricing declines have flattened in recent years as each incremental amount of cost reduction becomes more difficult to achieve. Accordingly, it would not be reasonable to expect that 2020 pricing would decline in amounts significant enough to make Mr. Robinson's assumptions reasonable. For instance, in order to reach even the high-cost scenario amount used by Witness Robinson [BEGIN CONFIDENTIAL] [END CONFIDENTIAL], the median price would need to decline by [BEGIN CONFIDENTIAL] [END CONFIDENTIAL] year over year. To reach the mid-cost pricing scenario, it would need to decline by nearly [BEGIN CONFIDENTIAL] [END CONFIDENTIAL].

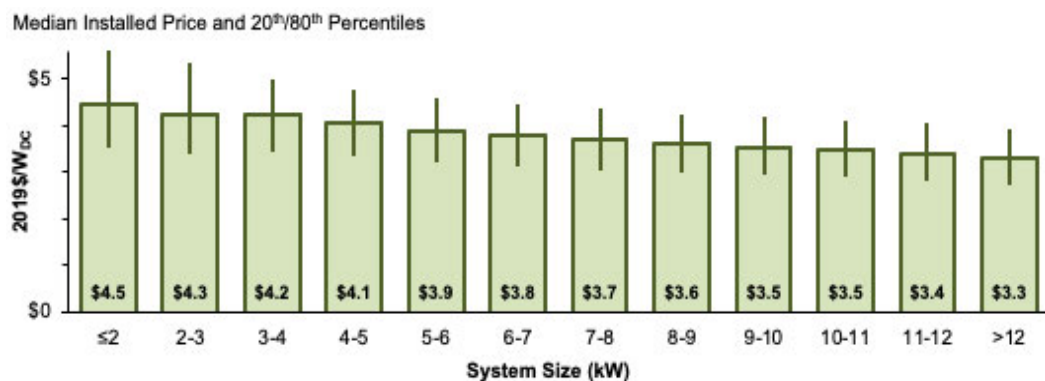
Q. PLEASE EXPLAIN HOW WITNESS ROBINSON'S APPLICATION OF SOLAR INSTALLATION COST SCENARIOS IS UNREALISTIC FOR SMALLER SYSTEMS.

A. Even if one accepts the projected installed cost estimates presented by Witness Robinson, which I do not, it is inappropriate to apply such cost assumptions

across the board regardless of system size. As I previously noted, Witness Robinson's projections of payback period and levelized bill ratios for residential Solar Choice systems assumes a system size of 3 kW, which is significantly smaller than the average system size used by Company Witness Everett in her own analyses. While one might reasonably assume that a Solar Choice tariff design that devalues exports would motivate customers to install smaller systems, it is not appropriate to apply an *average* installed cost amount to systems that are significantly smaller than average. Smaller systems tend to cost significantly more on a per watt basis than average or large systems.

As illustrated in Figure 6 below, sourced from the LBNL Report, economies of scale are readily apparent in the median installed costs for 2019 residential solar systems. Table 12 contains the data associated with this Figure from the report, to which I have added the lowest two rows showing the 20th and 80th percentiles.⁶⁹

Figure 6: Effects of System Size on Residential Installed Costs



⁶⁹ LBNL Report. Summary Data Tables, tab labeled "Economies of Scale". December 2020. Available at: <https://emp.lbl.gov/tracking-the-sun>.

Table 12: Effects of System Size on Residential Installed Costs

	Residential System Size (kW)											
	≤2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-11	11-12	>12
# of Systems	719	6,101	13,308	19,156	22,144	18,082	17,069	13,644	9,792	7,530	5,891	13,384
Median \$/W	4.5	4.3	4.2	4.1	3.9	3.8	3.7	3.6	3.5	3.5	3.4	3.3
20th Percentile	3.5	3.4	3.5	3.3	3.2	3.1	3.0	3.0	2.9	2.9	2.8	2.7
80th Percentile	7.1	5.3	5.0	4.8	4.6	4.4	4.4	4.2	4.2	4.1	4.0	3.9

I also note that Table 12 shows that even the lowest 20th percentile of 2019 pricing for the largest systems (9 kW and above) that benefit from the greatest economies of scale is approximately the same as the high-cost scenario used by Company Witness Robinson for 2020 residential pricing. For small systems of the size (3 kW) reflected in Mr. Robinson's solar economics projections, the lowest 20th percentile for 3 – 4 kW systems is roughly [BEGIN CONFIDENTIAL] [END CONFIDENTIAL] higher than the 2020 high-cost scenario employed by Witness Robinson.

Q. PLEASE ELABORATE ON WHY THE LOW-COST SCENARIOS SHOULD BE DISREGARDED IN THEIR ENTIRETY.

A. The low-cost scenario, in addition to assuming extraordinarily low installed system costs, also assumes that the federal ITC in 2021 is set at 30% of installed costs.⁷⁰ At the time Witness Robinson filed his testimony the federal ITC was slated to decline from 26% in 2020 to 22% in 2021. Subsequently, in December 2020 the present level of 26% was extended for two more years for 2021 and

⁷⁰ Robinson Direct at 6:17-18.

1 2022.⁷¹ Assuming that a further increase in the federal ITC will occur would be
2 highly speculative and seems comparatively unlikely given the very recent
3 legislative compromise that extended it at 26%.

4 **Q. WOULD THE IMPLICATIONS OF SOLAR CHOICE DIFFER FOR THE**
5 **ECONOMICS OF LEASED SYSTEMS RELATIVE TO CUSTOMER-**
6 **OWNED SYSTEMS?**

7 A. The economics of leased systems would suffer to the same or greater degree as
8 they would for customer-owned systems. While the simple payback period does
9 not provide a good measure of the attractiveness of a leased system because there
10 is no “payback” period for the customer, the fundamental drivers of system cost
11 and the savings rate do not change. The attraction of a solar lease is based on the
12 expectation of immediate and recurring overall bill savings. To the extent that
13 providers cannot offer a solar lease that provides net savings because the
14 electricity bill savings are too low to support it, few, if any customers are likely to
15 choose a leasing arrangement. I note in this respect that the Company’s
16 projections of the levelized bill ratio under Solar Choice are fairly marginal even
17 under assumptions and scenarios engineered to reflect *optimal* circumstances,
18 such as low system costs and a low load coverage ratio, that would not reflect
19 what would be more typical.

⁷¹ Solar Energy Industries Association. “COVID Aid Package Makes Initial Commitment to a Clean Energy Recovery”. December 21, 2020, *available at*: <https://www.seia.org/news/covid-aid-package-makes-initial-commitment-clean-energy-recovery>.

Q. CAN YOU PROVIDE A COMPARISON BETWEEN NEM AND SOLAR CHOICE THAT IS MORE APPROPRIATE FOR LEASED SYSTEMS?

A. Witness Robinson's levelized bill ratio metric would be appropriate for this purpose. However, because the Company did not provide a full working version of his model it is not possible to recreate the analysis to address more realistic scenarios than the high load and small system scenario he presents, or to do so using other alternative assumptions, such as those for solar system costs and the solar production profile.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR VIEW OF THE COMPANY'S SOLAR CHOICE TARIFF PROPOSAL AS IT RELATES TO ACT 62.

A. Dominion's Solar Choice proposal would effectively eliminate the customer-sited solar industry by reducing customer opportunities for bill savings under most circumstances to the point where installing solar is no longer financially attractive to customers. This outcome is in direct conflict with both the general intent and the specific directives contained in Act 62, which call for a measured approach that balances considerations of cost of service, long-term costs and benefits, a customer's right to consume customer-generated energy behind the meter without penalty, and the potential for industry disruption. Furthermore, the Company has failed to meet a basic requirement of Act 62 dictating that the actual cost to serve solar customers and their impacts on cost of service of their broader class be considered as part of the evaluation of net metering costs and benefits and Solar Choice tariffs.

1 The Company's projections of the impacts of Solar Choice on the
2 opportunities for customers to save money by installing solar are based on
3 assumptions and scenarios that are both: (a) flawed with respect to on the ground
4 realities of system cost and savings opportunities, and (b) internally conflicting
5 with one another. Those projections indicate that under very narrow
6 circumstances involving a confluence of multiple supporting factors, a very small
7 number of customers might still find customer-sited solar financially attractive.
8 However, this is not a path to maintaining, let alone fostering growth of, the solar
9 industry that South Carolina has built over the last several years, as required by
10 Act 62.

11 **Q. WHAT ARE YOUR RECOMMENDATIONS FOR A DOMINION SOLAR**
12 **CHOICE TARIFF?**

13 A. The Commission should reject the Company's proposed Solar Choice tariff and
14 instead adopt a Solar Choice tariff based on my alternative proposal. My
15 alternative Solar Choice tariff proposal contains the following elements:

- 16 1. BFC and Minimum Bill: Solar Choice BFCs are set at the amount for the
17 otherwise applicable rate schedule and a minimum bill is set at the amount
18 established for the otherwise applicable time-of-use TOU rate option.
- 19 2. Mandatory TOU Rate: Solar Choice customers take TOU service and may
20 do so under any TOU rate that would be available to them if they were not
21 Solar Choice customers. However, I suggest that the Commission delay
22 implementation of mandatory TOU under Solar Choice until it is confident
23 that Solar Choice customers will have the proper information and tools to

1 respond to a TOU rate design, including access to at least 12 months of
2 interval usage data, which will become increasingly available as the
3 deployment of advanced metering infrastructure (“AMI”) progresses.

4 3. Exported Energy: Solar Choice retains the existing retail rollover design
5 under the current NEM program and relies on TOU rates to provide
6 appropriate price signals to customers.

7 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

8 A. Yes.

**BEFORE THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION
DOCKET NO. 2020-229-E**

In the Matter of:)
Dominion Energy South Carolina,)
Incorporated's Establishment of a)
Solar Choice Metering Tariff Pursuant)
to S.C. Code Ann. Section 58-40-20)

**DIRECT TESTIMONY OF
JUSTIN R. BARNES
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION AND
SOLAR ENERGY INDUSTRIES ASSOCIATION**

EXHIBIT JRB-1

JUSTIN R. BARNES

(919) 825-3342, jbarnes@eq-research.com

EDUCATION

Michigan Technological University

Houghton, Michigan

Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma

Norman, Oklahoma

Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present

Senior Analyst & Research Manager, March 2013 – July 2015

EQ Research, LLC and Keyes, Fox & Wiedman, LLP

Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource (DER) value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;

Policy Analyst, September 2007 – December 2011

North Carolina Solar Center, N.C. State University

Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.



- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future*. 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues*. July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina; and Solar in Small Communities: Columbia, Missouri*. 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On*. 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar*. 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends*. Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets*. 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar*. 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY & OTHER REGULATORY ASSISTANCE

Virginia State Corporation Commission. Docket No. PUR-2020-00134. January 2021. On behalf of the Behind the Meter Solar Alliance. Docket for Dominion Virginia's 2020 RPS Plan. Offered testimony supporting the designation of small-scale resource carve-out eligibility being limited to behind the meter resources, based on the underlying Virginia statute and other public policy reasons.

South Carolina Public Service Commission. Docket No. 2019-182-E. October 2020. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a cost-benefit analysis methodology and protocols for net metering and DERs. Provided discussion of historic regulatory use of DG cost-benefit and cost of service studies, how results should be viewed, and a discussion of the role of economic benefits and resiliency in DER cost-benefit analyses.

Kentucky Public Service Commission. Docket No. 2020-00174. October 2020. On behalf of the Kentucky Solar Industries Association. Kentucky Power general rate case. Provided an evaluation and critique of the cost of service support for, and design of, Kentucky Power's proposed net metering



successor tariff and offered recommendations for developing cost-based DER rate designs. Also recommended changes to the utility's QF tariff and calculation of capacity costs.

New Jersey Board of Public Utilities. Docket No. EO18101111. September 2020. On behalf of Sunrun, Inc. Public Service Gas and Electric energy storage deployment plan proposal. Offered alternative proposal for a program utilizing non-utility owned energy storage assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

Virginia State Corporation Commission. Docket No. PUR-2020-00015. July 2020. On behalf of Appalachian Voices. Appalachian Power Company general rate case. Analysis of the cost basis for the residential customer charge, the Company's winter declining block rate proposal, and a proposed Coal Asset Retirement Rider (Rider CAR) providing for advance collection of anticipated accelerated depreciation of coal generation assets. Provided an alternative residential customer charge recommendation and an alternative rates proposal for addressing winter bill volatility for electric heating customers.

North Carolina Utilities Commission. Docket No. E-7 Sub 1219. April 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

North Carolina Utilities Commission. Docket No. E-7 Sub 1214. January 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

Virginia State Corporation Commission. Docket No. PUR-2019-00060. November 2019. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Analysis of the cost basis for the residential customer charge, proposal to change the residential customer charge from a monthly charge to a daily charge, and design of proposed customer green power program and utility owned commercial behind the meter solar proposal. Proposed modified optional rate structure for mid- to large-size non-residential customers with on-site solar and/or low load factors.

Georgia Public Service Commission. Docket No. 42516. October 2019. On behalf of Georgia Interfaith Power and Light, Southface Energy Institute, and Vote Solar. Georgia Power Company general rate case application. Analysis of the cost basis for the residential customer charge, the validity of the utility's minimum-intercept study, and a proposal to change the residential customer charge from a monthly charge to a daily charge.

Hawaii Public Utilities Commission. Docket No. 2018-0368. July 2019. On behalf of the Hawaii PV Coalition. Hawaii Electric Light Company (HELCO) general rate case application. Provided analysis of HELCO's proposed changes to its decoupling rider to make the decoupling charge non-bypassable and the alignment of the proposed modifications with state policy goals and the policy rationale for decoupling.

Virginia State Corporation Commission. Docket No. PUR-2019-00067. July 2019.* On behalf of the Southern Environmental Law Center. Appalachian Power Company residential electric vehicle (EV) rate proposal. Provided review and analysis of the proposal and developed comments discussing principles of time-of-use (TOU) rate design and proposing modifications to the Company's proposal to support greater equity among rural ratepayers and greater rate enrollment. ***This work involved comment preparation rather than testimony.**

New York Public Service Commission. Case No. 19-E-0065. May 2019. On behalf of The Alliance for Solar Choice. Consolidated Edison (ConEd) general rate case application. Provided review and analysis of the competitive impacts and alignment with state policy of ConEd's energy storage, distributed energy resource management system, and earnings adjustment mechanism (EAM) proposals. Proposed model for improving the utilization of customer-sited storage in existing demand response programs and an alternative EAM supportive of utilization of third party-owned battery storage.

South Carolina Public Service Commission. Docket No. 2018-318-E. March 2019. On behalf of Vote Solar. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

South Carolina Public Service Commission. Docket No. 2018-319-E. February 2019. On behalf of Vote Solar. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

New Orleans City Council. Docket No. UD-18-07. February 2019. On behalf of the Alliance for Affordable Energy. Entergy New Orleans general rate case application. Analysis of the cost basis for the residential customer charge, rate design for AMI, DSM and Grid Modernization Riders, and DSM program performance incentive proposal. Developed recommendations for the residential customer charge, rider rate design, and a revised DSM performance incentive mechanism.

New Hampshire Public Utilities Commission. Docket No. DE 17-189. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

North Carolina Utilities Commission. Docket No. E-7 Sub 1146. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.



Public Utility Commission of Texas, Control No. 46831. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

Utah Public Service Commission, Docket No. 14-035-114. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

Public Utility Commission of Texas, Control No. 44941. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

Oklahoma Corporation Commission, Cause No. PUD 201500271. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Masters Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

